Market Power in the Nordic Power Market

En rapport skriven av
Econ Pöyry AB
på uppdrag av Konkurrensverket

Förord

I Konkurrensverkets uppdrag ligger bl.a. att främja forskning på konkurrensområdet. Av särskilt intresse är utvecklingen på den regelreformerade elmarknaden och då bl.a. möjligheterna till utövande av marknadsmakt. Konkurrensverket har tidigare t.ex. publicerat en rapport av professor emeritus Einar Hope som ur ett konkurrenspolicy-perspektiv belyste frågan om dominans och marknadsmakt på den nordiska elmarknaden (Konkurrensverkets uppdragsforskningsserie 2005:3). Ett mer traditionellt angreppssätt är att med hjälp av ekonomiska modeller analysera möjligheterna till att utöva marknadsmakt.

Med dessa utgångspunkter gav Konkurrensverket i november 2006 ekonomie doktor Niclas Damsgaard vid Econ Analys AB (numer Econ Pöyry AB) i uppdrag att tillsammans med ett forskarteam från Econ genomföra ett projekt om betydelsen av marknadsmakt på den nordiska elmarknaden. Forskningsprojektet hade två delsyften: dels att analysera potentialen för marknadsmakt på elmarknaden och dels att studera utövandet av marknadsmakt på elmarknaden. Resultaten av Econ Pöyrys studie presenteras i denna sammanläggningsrapport som en sammanfattande rapport och två delrapporter. Projektet har delfinansierats av den norska konkurrensmyndigheten, Konkurransetilsynet.

Det är författarna själva som svarar för innehåll och slutsatser i rapporterna. Slutsatserna behöver alltså inte nödvändigtvis återspegla Konkurrensverkets uppfattning.

Stockholm i februari 2008

Claes Norgren
Generaldirektör

Preface

One of the Swedish Competition Authority’s tasks is to initiate and support relevant research within the fields of competition and public procurement. Of special interest in this context are the developments in the liberalised electricity market, inter alia on the possibilities to exercise market power. E.g., in 2005 the Swedish Competition Authority published a report by Professor Emeritus Einar Hope, who elaborated on the question of dominance and abuse of market power in the Nordic electricity market from a competition policy perspective (Commissioned Research 2005:3). A more traditional approach to the study of market power is to analyse the exercise of market power using economic modelling techniques.

With this as a starting point, the Swedish Competition Authority, in November 2006, gave Ph.D. Niclas Damsgaard at Econ Analys AB (now Econ Pöyry AB) a commission, together with a research team from Econ, for a project looking at the potential and importance of market power in the Nordic electricity market. The purpose of the research project was twofold: first to analyse the potential for market power, and second to study the actual exercise of market power in the electricity market. The results of Econ Pöyry’s study are presented in this report as a summary of findings (available only in Swedish) and two separate reports. The project has been financed in part by the Norwegian Competition Authority.

The authors themselves are responsible for the analysis and the conclusions in the reports. Thus, any views expressed in the reports are those of the authors and need not necessarily reflect those of the Swedish Competition Authority.

Stockholm in February 2008

Claes Norgren
Director-General

Innehåll

PM N-2007-068

Marknadsmakt på elmarknaden:

Sammanfattande rapport

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Framtagen på uppdrag av Konkurrensverket

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Sammanfattning

Inom ramen för ett forskningsprojekt finansierat av Konkurrensverket har två studier genomförts. I den första studien har en modell för att simulera potentialen för att utöva marknadsmakt på den nordiska elmarknaden utvecklats och i den andra studien har vi studerat utövandet av marknadsmakt på elmarknaden.

Del 1: Potentialen för marknadsmakt

Vi modellerar potentialen för marknadsmakt på den nordiska elmarknaden och Tyskland med en numerisk simuleringsmodell. Strategiskt beteende modelleras med en Supply function equilibrium (SFE) ansats. Om vi antar att de stora producenterna agerar strategiskt, men inte koordinerat, stiger priserna med 11 – 27 % i de olika marknadsområdena. Den totala produktionen minskar med ca 1,5 %, men med stora variationer mellan områdena.

Två scenarier där det största företaget i Sverige (Vattenfall) och Norge (Statkraft) delas ger minskad marknadsmakt, men effekten är relativt liten. En delning av Vattenfall i en vattenkraftdel och en termisk del minskar påslaget över marginalkostnad i Sverige, Finland och Själland med ca 1/5, men mindre i andra områden. Andra delningsalternativ kan ge större minskning av potentialen för marknadsmakt. En delning av Statkraft har en liknande men mindre effekt.

Modellsimuleringarna visar också att kundernas priskänslighet är av stor betydelse. Detta innebär dels en betydande osäkerhet i analysen eftersom det råder stor osäkerhet om hur stor priskänsligheten är. Det visar dock också på att åtgärder för att öka priskänsligheten kan ha stor betydelse för att minska potentialen för marknadsmakt.

Man kan förvänta sig att potentialen för att utöva marknadsmakt är störst i knapphetsperioder, exempelvis under s.k. ”torrår”, eftersom marknaden då klareras på en relativt sett ”brant” del av utbudskurvan. Det innebär att små variationer i volymen har en stor effekt på priset. Det finns dock andra faktorer som kan dra i motsatt håll. I simuleringar som vi har gjort av ett torrår och ett våtår finner vi störst potential för marknadsmakt i våtåret. Utövandet av marknadsmakt sker då främst genom att produktionen reduceras i låg- och mellanlastperioder för att motverka att priset faller till de mycket låga nivåer som blir resultatet under perfekt konkurrens. Under torrår utövas marknadsmakt främst genom en minskning av produktionen under höglastperioder vintertid.

Del 2: Utövande av marknadsmakt.

Vi använder en sofistikerad modell för den nordeuropeiska elmarknaden för att studera om marknadsmakt har utövats på den nordiska elmarknaden, genom att jämföra faktiska priser och produktionsmönster med resultat från modellsimuleringar. Vi studerar tre tidsperioder från 2001 till 2006 med olika karaktäristika avseende fundamentala marknadsförhållanden. Två bristsituationer (sommaren till vintern 2002/03 och sommaren till hösten 2003) och en normalsituation (sommaren till hösten 2001) har valts ut för analysen. Enbart för 2002/03 finner vi starka indikationer på utövande av marknadsmakt och enbart för ett marknadsområde (Jylland). Kring årsskiftet 2002/03 nådde priserna mycket höga nivåer och de faktiska priserna är klart över de simulerade priserna för de flesta marknadsområden. Störst skillnad mellan faktiska och simulerade priser återfinns för Jylland följt av Själland. För 2006 är de observerade genomsnittliga priserna något högre än de simulerade priserna i samtliga marknadsområden och resultatet är kvalitativt överensstämmande med vad som skulle kunna förväntas om marknadsmakt utövades. Det kan dock inte uteslutas att skillnaden mellan faktiska priser och simulerade priser är orsakade av skillnader i förväntningar snarare än marknadsmakt. För alla andra perioder och regioner är de faktiska priserna något under de simulerade priserna. Den övergripande slutsatsen är därmed att, med något undantag, kan merparten av prisvariationerna som har observerats under senare år förklaras av fundamentala marknadsförhållanden snarare än utövande av marknadsmakt.

1 Inledning[1]

Under de senaste 10-20 åren har elmarknader runt om i världen öppnats upp för en ökad grad av konkurrens. Erfarenheterna av konkurrensutsättning av elmarknader har varit blandade. Detta beskrivs ofta som en våg av avregleringar, även om det i de flesta fall egentligen inte handlar om avregleringar undan om regelreformering. I de flesta fallen har produktion och försäljning av el blivit konkurrensutsatt, medan nätverksamheten istället har blivit kringgärdad av en hårdare och mer strikt regleringen. Nätverksamheten kan på goda grunder ses som ett naturligt monopol och utgör en *essential facility* för sektorn. Icke-diskriminerade tillgång till denna infrastruktur är därför viktig för en fungerande konkurrens på marknaden i dess helhet.

Det huvudsakliga syftet med dessa regelreformer runt om i världen har varit att förbättra effektiviteten i branschen genom att främja konkurrens. Produktionen av elektricitet sker generellt sett på marknader med relativt hög koncentrationsgrad och därför är en av de viktigaste forskningsfrågorna för den avreglerade elmarknaden hur man kan upptäcka och mäta marknadsmakt.

Erfarenheterna av s.k. avregleringar är blandade. Det finns uppenbara misslyckanden där Kalifornien är det kanske mest uppenbara fallet. I den andra änden av spektrumet finns sannolikt konkurrensutsättningen av elmarknaderna i Norden som i ett internationellt perspektiv framstår som lyckade. Det har dock framkommit misstankar om att elproducenterna agerar strategiskt i syfte att höja elpriset. Detta har särskilt aktualiserats med anledning av ett antal förvärv, företagsfusioner och ökat korsägande mellan elföretag i Norden.[2] I mediadebatten har politiker, myndigheter, elintensiv industri och företrädare för övriga näringslivet ofta refererar till den bristande konkurrensen. Detta gäller samtliga nordiska länder. I Danmark har även missbruk av marknadsmakt även påvisats av konkurrensmyndigheten. Elsam har befunnits skyldiga till att ha missbrukat sin marknadsmakt på marknaden i västra Danmark under 900 timmar i perioden 1 juli 2003 till 31 december 2004, vilket också har fastställts i domstol. Den danska konkurrensmyndigheten har vidare funnit att Elsam missbrukat sin dominerande ställning under 1484 timmar i perioden 1 januari 2005 till 31 december 2006, men detta har inte slutligt avgjorts i domstol. Konkurrensmyndigheten har också inlett utredningar angående eventuellt missbruk av marknadsmakt i östra Danmark.

1.1 Möjlighet att utöva marknadsmakt på den nordiska elmarknaden

De närmaste åren efter det att den svenska elmarknaden öppnades för konkurrens 1996 var prisutvecklingen gynnsam för konsumenterna, vilket kunde tas som intäkt för en väl fungerande konkurrens och en lyckad marknadsöppning. Under de senaste åren har

[1] Denna rapport sammanfattar resultaten av ett forskningsprojekt om marknadsmakt på elmarknaden finansierat av Konkurrensverket. Projektet har genomförts av en forskargrupp inom Econ Pöyry under ledning av Niclas Damsgaard. Mer detaljerade resultat återfinns i två vetenskapliga uppsatser (Damsgaard och Munthe, 2007 samt Damsgaard, Skrede och Torgersen, 2007).

[2] För en beskrivning av förändringar i marknadsstrukturen på elmarknaden under de senaste åren hänvisar vi till den gemensamma rapporten från de nordisk konkurrensmyndigheterna ”Capacity for Competition. Investing for an efficient Nordic Electricity Market”, Nordic Competition Authorities, Report No 1, 2007.

priserna istället vänt uppåt, med såväl ett högre genomsnittligt pris och periodvis extremt höga priser på Nord Pool.

En viktig förklaringsfaktor till de kraftiga prisvariationerna är väderförhållanden. Det nordiska elsystemet är i stor utsträckning baserat på vattenkraft, även om den marginella produktionsteknologin ofta utgörs av kolkraft i Danmark eller Tyskland. Det betydande inslaget av vattenkraft medför dock att variationer i nederbörd har en avsevärd effekt på den tillgängliga produktionskapaciteten och därmed en stor påverkan på elsystemets marginalkostnad. Vidare påverkar temperaturen efterfrågan bland annat eftersom många hushåll har elvärme. Sedan januari 2005 finns en ny betydelsefull prisdrivande faktor i form av handel med utsläppsrätter för koldioxid. Eftersom det nordiska systemets marginalkostnad under en stor del av tiden bestäms av kostnaden för kolkraft får detta stor betydelse.

Möjligheterna för ett sådant strategiskt agerande torde vara särskilt stora i perioder med hög efterfrågan och begränsad överföringskapacitet mellan olika delar av den nordiska marknaden. Under senare år har det nordiska elsystemet präglats av en tilltagande knapphet. Situationen under vintern 2002/03 utgör ett exempel på en sådan period. Det är därför av stort intresse att avgöra den relativa betydelse av utövande av marknadsmakt i synnerhet i perioder som denna.

Elmarknaden är speciell på det sätt att potentialen för marknadsmakt kan variera kraftigt mellan olika perioder. På de flesta elmarknader finns liten potential för utövande av marknadsmakt under låglastperioder (timmar). Samtidigt kan det på samma marknader finnas en betydande potential för marknadsmakt under topplastperioder. Detta beror till stor del på att när efterfrågan stiger över en viss nivå blir såväl transmissions- som produktionskapacitet för potentiella konkurrenter uttömda och residualefterfrågan kan mötas endast av ett fåtal företag. På den nordiska marknaden, med sitt stora beroende av vattenkraft, förstärks denna effekt av tillgången på vatten. Vid liten tillrinning minskar tillgänglig produktionskapacitet, vilket i sig har en liknande effekt som en kraftig ökning av efterfrågan. Den kombinationen av hög efterfrågan och ett minskat utbud som exempelvis rådde under vintern 2002/03 kan därför medföra en betydande ökning av potentialen för marknadsmakt.

Vattenkraftens stora betydelse för det nordiska elsystemet har dock också en generell påverkan på möjligheterna att utöva marknadsmakt. En reduktion av den totala producerade volymen vattenkraftproducerad el innebär att man måste spilla vatten. Den låga rörliga kostnaden för vattenkraften gör att det är förhållandevis kostsamt att reducera volymen vattenkraft eftersom det är en stor differens mellan marknadspriset och produktionskostnaden. I tillägg kan det ifrågasättas i vilken grad det är praktiskt möjligt att ”spilla vatten” utan att det upptäcks. Det kan dock vara möjligt för en producent att agera på ett sådant sätt att producenten måste spilla vatten till följd av fulla magasin. Emellertid är sannolikt det mest betydelsefulla sättet att utöva marknadsmakt i ett vattenkraftsystem att flytta produktionen i tid. Det innebär att man reducerar produktionen vid tidpunkter då det har en stor effekt på priset (normalt höglastperioder), men i gengäld ökas produktionen vid andra tidpunkter (normalt låglastperioder). Detta är en viktig egenskap med vattenkraftdominerade system vilket man måste ta hänsyn till i en analys av marknadsmakten på elmarknaden.

1.2 Projektets syfte

Det första syftet är att utveckla en marknadsmaktsmodell för den nordeuropeiska elmarknaden. Med hjälp av denna modell ska *potentialen för marknadsmakt* på den nordiska elmarknaden kunna analyseras. Eftersom den nordiska elmarknaden påverkas av situationen på kringliggande marknader i Nordeuropa måste en sådan modell även omfatta dessa länder. Modellen kan bland annat utgöra ett viktigt verktyg för att bedöma effekter av företagskoncentrationer på elmarknaden, samt vid analyser av policyförslag. Med hjälp av modellen kan sedan ett antal intressanta scenarier analyseras, vilket dels kommer att ge ökad förståelse för *risker för utövande* av marknadsmakt, samt ge en *kvantitativ uppskattning av hur stor effekten* av utövande av marknadsmakt kan ha.

Det andra syftet är studera *utövandet av marknadsmakt* på den nordiska elmarknaden. Genom att analysera priser, produktionskostnader och kvantiteter kan vi mäta i vilken grad priserna på den nordiska elmarknaden har överstigit de nivåer som ges av perfekt konkurrens. Perioder som bedöms som särskilt intressanta i förehållande till utövande av marknadsmakt har valts ut för studien.

Målet med forskningsprojektet är att bidra med ökad kunskap om betydelsen av marknadsmakt på den nordiska elmarknaden. Kunskapen om detta är av stor betydelse för såväl politikåtgärder för att öka konkurrensen på elmarknaden, som eventuella utredningar eller åtgärder för att stävja konkurrensbegränsade beteende på elmarknaden.

I detta projekt har vi endast studerat marknadsmakt på den nordiska råkraftmarknaden (grossistmarknaden). Marknadsmakt på detaljistmarknaden, eller betydelsen av vertikal integration mellan producenter, detaljister och nätföretag har inte behandlats.

2 Potential för marknadsmakt på den nordiska elmarknaden

Det finns flera möjliga ansatser för att bedöma potentialen för utövande av marknadsmakt på olika marknader. Exempelvis är det vanligt med olika typer av koncentrationsmått (t.ex. HHI). Elmarknaden skiljer sig från många andra marknader genom att marknadsförhållandena, och därmed potentialen för marknadsmakt, kan variera väsentligt från timme till timme. Orsaken till detta är att det inte är praktiskt möjligt att lagra elektricitet och att i första hand efterfrågan varierar över tid. ”Marginella” aktörer kan också få ett oproportionerligt stort inflytande över prissättningen vid vissa tidpunkter, genom att deras marknadsandel i ett prissättande lastsegment är högt. För att fånga upp detta har olika indikatorer utvecklats. Pivotal Supplier Indicator (PSI) försöker fånga om en given producent är nödvändigt för att möte efterfråga vid en given tidpunkt genom att mäta om producentens kapacitet är större än överskottsutbudet på marknaden (tillgänglig kapacitet utöver efterfrågan). Om så är fallet är producenten ”pivotal” i denna tidpunkt (PSI = 1 annars = 0). PSI för varje timme summeras sedan för att bestämma andelen av tiden som en aktör är ”pivotal”. Beräknande av denna indikator kräver tillgång till timvis data. Det finns också olika alternativa versioner av PSI. I USA har Federal Energy Regulatory Commission (FERC) använt Supply Margin Assessment (SMA) för att ”screena” för marknadsmakt i koncentrationsärenden. Enligt denna indikator är ett företag ”pivotal” om dess kapacitet överstiger marknadens överskottskapacitet utöver topplastefterfrågan, vilket bl.a. innebär att indikatorn kan "triggas" även om företaget bara är ”pivotal” under en enda timme. FERC har också kompletterat denna analys med en analys av marknadsandelar på säsongsmässig grund. Systemoperatören i Kalifornien (CAISO) har också utvecklat Residual Supply Index (RSI), som liknar PSI men mäts på en kontinuerlig skala. I Sverige har också Energimarknadsinspektionen (2006) redovisat ett anpassat RSI för de tre största företagen i Sverige för år 2005.[3]

2.1 Modellering av marknadsmakt

Indikatorer kan ge viss vägledning kring potentialen för utövande av marknadsmakt. Elmarknader är dock generellt tämligen komplicerade där en mängd faktorer påverkar timme för timme. En alternativ ansats är att modellera marknadsmakt med hjälp av en numerisk modell. Såväl för Norden som internationellt finns ett antal modeller där marknadsmakt modelleras utifrån en Cournot ansats. Andersson och Bergman (1995) utvecklade en statisk Cournot modell för den svenska elmarknaden, vilken i senare skede har utvecklats av Amundsen och Bergman (2002). På europeisk nivå har man inom EMELIE[4] projektet utvecklat en statisk spelteoretisk modell, som möjliggör olika antagande avseende det strategiska beteenden. Problemet med denna typ av statiska en-periodsmodeller är att man förlorar den dynamiska aspekten i marknadsbeteendet. Detta är särskilt viktigt på marknader med mycket vattenkraft. För en vattenkraftproducent är det kanske inte i första hand genom att hålla tillbaka den samlade produktionen som marknadsmakt utövas, utan genom att flytta produktionen i tid. Scott och Read (1996) har utvecklat en Cournotmodell med optimering av vattenkraften i varje steg.

[3] Det anpassade RSI förefaller ligga närmare PSI indikatorn.

[4] Electricity Market Liberalisation in Europe

I en Cournotmodell uttrycks producenternas strategier enbart i termer av kvantiteter. Detta innebär bland annat att modellerna blir känsliga för antaganden kring efterfrågeelasticiteter. I realiteten lämnas dock budkurvor, eller pris-kvanitet par. Så kallade supply function equilibrium[5] (SFE) modeller försöker fånga upp det faktiska budbeteendet. SFE modeller med osäkerhet om efterfrågan introducerades av Klemperer och Meyer (1989) och anpassades till elmarknader av Bolle (1992) och Green och Newbery (1992). Sedan dess finns ett stort antal uppsatser där SFE modeller använts. SFE modeller är dock generellt tämligen komplicerade. Generellt kan man inte finna unika jämvikter, de kan vara svåra att lösa för mer komplicerade marknadssituationer och är svåra att anpassa till icke-symmetriska fall.

Sioshansi och Oren (2007) analyserar hur väl SFE modeller fångar faktiskt budbeteende genom att jämföra med optimala budkurvor från komplicerade SFE modeller. Deras slutsats är att stora producenters beteende svarar relativt väl mot det teoretiskt optimala beteendet, medan detta inte gäller för mindre producenter. Det är därmed tveksamt om komplicerade SFE modeller ger bättre prediktioner jämfört med enklare modeller. De menar att exempelvis linjära SFE modeller ger förhållandevis riktiga prisprediktioner och även konventionella Cournotmodeller kan vara tillräckliga för att bedöma jämviktspriset. Wolfram (1998, 1999) har analyserat den engelska marknaden och menar att SFE modellerna inte återger spotmarknaderna särskilt väl och att faktiska priser har varit lägre än dessa modeller förutspår.

2.2 Vår modell

Mot ovanstående bakgrund har vi utvecklat en numerisk simuleringsmodell med en SFE ansats för den nordiska elmarknaden (även Tyskland finns representerat) Simuleringsmodeller är ett alternativ till formella jämviktsmodeller när problemet är alltför komplext för att hanteras inom ramen för en formell matematisk jämvikt. Med modellen analyserar vi ett icke-kooperativt beteende, dvs. aktörerna kan inte ingå vare sig implicita eller explicita karteller.

Modellen innefattar en relativt detaljerat representation av det nordiska kraftsystemet. Marknadsmaktsmodellen är uppbyggd kring ECON Classic som är en fundamental kraftmarknadsmodell för den europeiska kraftmarknaden utvecklad av ECON. ECON Classic är en perfekt konkurrensmodell som regelbundet används såväl i forskningsprojekt som för kommersiella applikationer (exempelvis långsiktiga prisprognoser). Eftersom vattenkraften är betydande på den nordiska kraftmarknaden är det viktigt att modellen kan representera vattenkraft med magasin på ett adekvat sätt, dvs. ta hänsyn till systemets möjligheter att lagra vatten över en längre tid. Modellen optimerar därmed användandet av vattnet över året, med hänsyn taget till inflöde och magasinsbegränsningar.

Aktörernas strategiska beteende tas in genom en sökalgoritm[6] där vi söker efter optimala påslag i varje lastsegment[7] för företag som (exogent) definieras som

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[5] Utbudsfunktionsjämvikt

[6] Se Damsgaard och Munthe (2007) för en närmare beskrivning

[7] Modellen har i nuvarande version två säsonger (sommar, vinter) och tre lastsegment i varje säsong, dvs. totalt sex lastsegment.

strategiska.[8] För företag som är verksamma i flera marknadsområdet kan påslaget variera mellan dessa områden. Vidare kan olika påslag användas för vattenkraft och termisk produktion användas. Norden är uppdelat i fem regioner (Sverige, Norge, Finland, östra Danmark och västra Danmark).[9]

2.3 Modellresultat

Vi har använt modellen för att analysera potentialen för prisökningar till följd av utövande av marknadsmakt dels givet dagens marknadsstruktur och dels för två scenarier där Vattenfall respektive Statkraft har delats. Vi finner att det finns en betydande potential för att utöva marknadsmakt på den nordiska elmarknaden. Råkraftpriset blir enligt modellsimuleringarna 11 – 27 % högre i de fem nordiska marknadsområdena om vi antar att de stora aktörerna agerar strategiskt och har marknadsmakt jämfört med en situation med perfekt konkurrens. Potentialen är störst i Danmark (Själland och Jylland) och mindre i Norge, Finland och Sverige. Detta återspeglar dels produktionsstrukturen i länderna med mer termisk produktion i Danmark och dels koncentrationsnivåerna. Det stämmer också väl överens med en allmän bild av att problemen med marknadsmakt har varit störst på den danska marknaden.

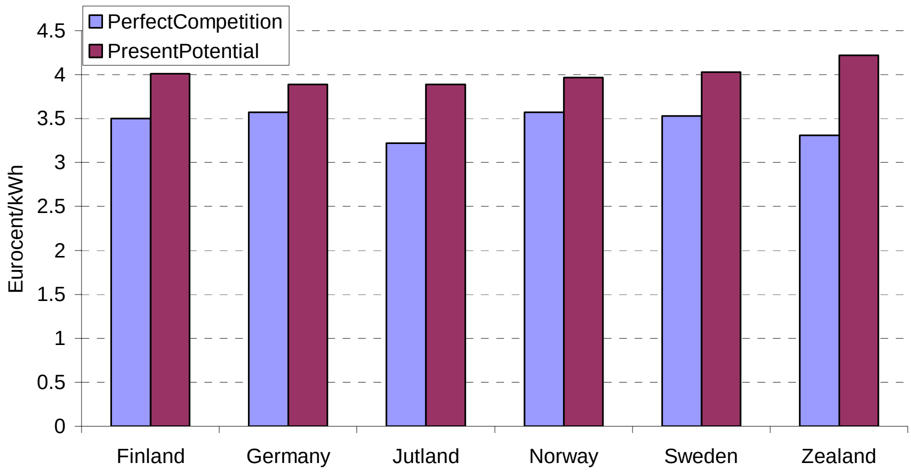
Under antagande om perfekt konkurrens ger modellen små prisskillnader såväl mellan områden som över tid. Genomsnittspriserna under perfekt konkurrens varierar från 3,2 eurocent/kWh (Jylland) till 3,6 eurocent/kWh (Norge och Tyskland). I Norge ger modellen ingen prisskillnad mellan olika laststegment, i Sverige varierar priserna med 0,1 eurocent/kWh och i Finland med 0.15 eurocent/kWh. De mer termiskt dominerade marknaderna i Danmark och Tyskland uppvisar större prisskillnader; 1,0 eurocent/kWh i Danmark (både östra och västra Danmark) och 2,8 eurocent/kWh i Tyskland. Även om modellen inte fångar upp den sanna prisstrukturen (för liten prisvariation särskilt i Norden) så återspeglar detta skillnaderna i teknologimix mellan de olika områdena.

Figur 2.1 visar den genomsnittliga priseffekten av utövande av marknadsmakt enligt modellsimuleringarna. För Sverige är det genomsnittliga priset under perfekt konkurrens 3,5 eurocent/kWh, medan det stiger till 4 eurocent/kWh om vi antar att de stora företagen agerar strategiskt, dvs. priset blir ca 14 % högre till följd av marknadsmakt.

[8] I de genomförda modellsimuleringarna har Vattenfall, E.ON, Fortum, Statkraft och DONG definierats som strategiska aktörer på den nordiska marknaden och Vattenfall, E.ON, RWE och EnBW på den tyska marknaden.

[9] Notera att det inte finns någon direkt förbindelse mellan elsystemen i östra och västra Danmark.

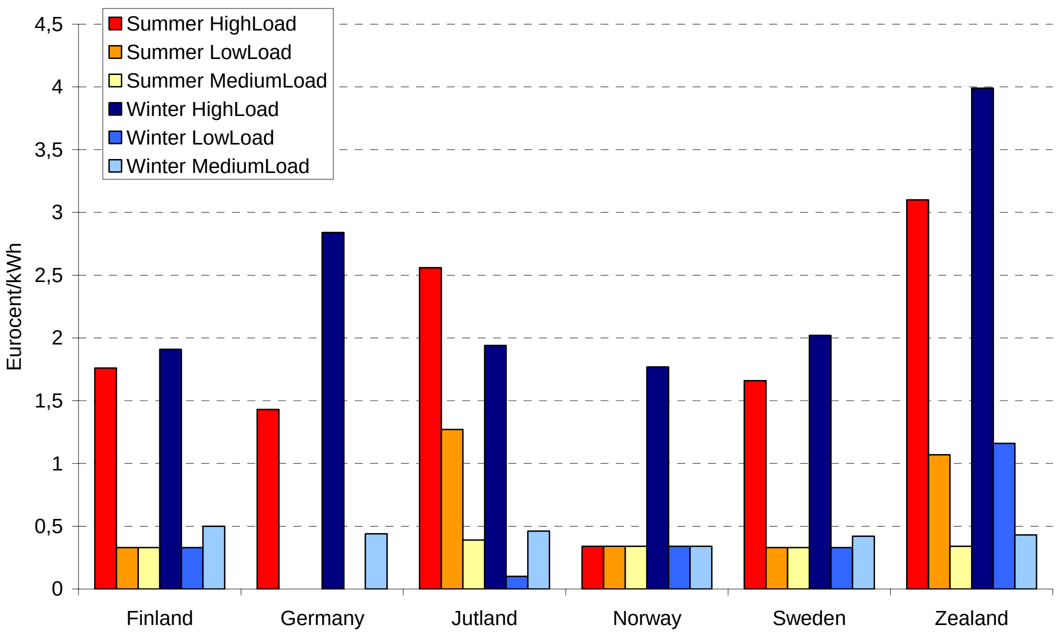
Figur 2.1 *Genomsnittliga simulerade priser under antagande om perfekt konkurrens respektive strategiskt beteende hos de stora producenterna, eurocent/kWh*



Källa: Egna modellsimuleringar

Figur 2.1 ovan visar den genomsnittliga priseffekten till följd av marknadsmakt, men skillnaderna är stora mellan olika lastsegment, vilket framgår av Figur 2.2. Höglastpriserna vintertid i Norden ökar till följd av marknadsmakt med mellan 1,8 och 4 eurocent/kWh. Även under höglasttimmarna under sommaren ökar priserna nästan lika mycket.

Figur 2.2 *Simulerade priser i olika prissegment, skillnad mellan perfekt konkurrens och marknadsmakt*



Källa: Egna modellsimuleringar

Marknadsmakt utövas dels genom en tillbakahållen produktion. Totalt sett i det modellerade området minskas produktionen med ca 1,5 % (14 TWh) och förbrukningen minskar också till följd av de högre priserna (minskning med knappt 12 TWh). I absoluta tal sker den största produktionsminskningen på Jylland (5,6 TWh eller 18,3 %), i Tyskland (4,3 TWh eller 0,7 %) och på Själland (4,1 TWh eller 22,8 %). Den relativa minskningen är klart störst i Danmark. I Sverige minskar produktionen med 0,4 % medan den är oförändrad i Norge. I Finland ökar faktiskt produktionen något (+0,3 %). Dessa regionala skillnader reflekterar dels ägarstrukturen men också produktionsmixen. I första hand är det produktion i relativt gamla koleldade kraftverk som minskas (totalt ca 15 TWh) eftersom dessa anläggningar generellt sett inte är särskilt lönsamma (liten skillnad mellan pris och marginalkostnad). Finska gaseldade kraftverk ägda av icke-strategiska aktörer ökar sin produktion med 3,5 TWh. Vattenkraftproduktionen minskas mycket lite (0,12 TWh).

Utöver marknadsmakt genom att reducera den totala produktionen utövas också marknadsmakt genom att ett förändrat produktionsmönster för vattenkraften. Det är generellt sett kostsamt för vattenkraftproducenter att ”spilla” vatten eftersom skillnaden mellan marginalkostnaden och marknadspriset vanligtvis är relativt stor. Genom att flytta produktionen över tid kan marknadsmakt utövas utan att producenten behöver spilla vattnet. Detta är lönsamt dels genom att marknadspriset påverkas olika vid olika tidpunkter av en volymförändring. I höglastperioder (ex. kalla vinterdagar) ökar priset typiskt sett mycket om produktion hålls tillbaka, medan under låglastperioder är priseffekten mycket mindre. Genom att producera mer under en låglastperiod för producenten betalt för den extra produktionen samtidigt som priset för företagets övriga produktion vid den tidpunkten endast påverkas i liten grad. Samtidigt minskas den tillgängliga produktionen i en höglastperiod då volymförändringen har en stor effekt på priset. I tillägg finns även en volymeffekt genom att det (lilla) prisfallet till följd av en ökad produktion i låglastperioden påverkar en mindre total volym jämfört med en prisförändring i en höglastperiod.

Modellsimuleringarna visar också att vattenkraftproduktionen minskar med 0,8 TWh vintertid (total vattenkraftproduktion i ett normalår i Sverige, Norge och Finland uppgår till ca 198 TWh). Samtidigt ökar vattenkraftproduktionen sommartid med 0,7 TWh.

Uppdelning av Vattenfall och Statkraft

Vi har även analyserat två scenarier där Vattenfall respektive Statkraft delas i två delar. Vattenfall delas i två företag där ett av företagen får all vattenkraftproduktion och det andra företaget får all övrig produktion. Statkraft delas i två företag som vardera får 50 % av kapaciteten, men ett av företagen får också minoritetsandelen som Statkraft har i E.ON Sverige.[10]

Figur 2.3 visar de genomsnittliga priserna i de tre scenarierna (dagens marknadsstruktur, delning av Vattenfall, delning av Statkraft). Delningen av Vattenfall sänker påslaget till följd av marknadsmakt med ca 1/5 i Sverige, Finland och Själland. Delningen av Statkraft har en liknande effekt även om prisminskningen generellt sett är mindre vid en delning av Statkraft.

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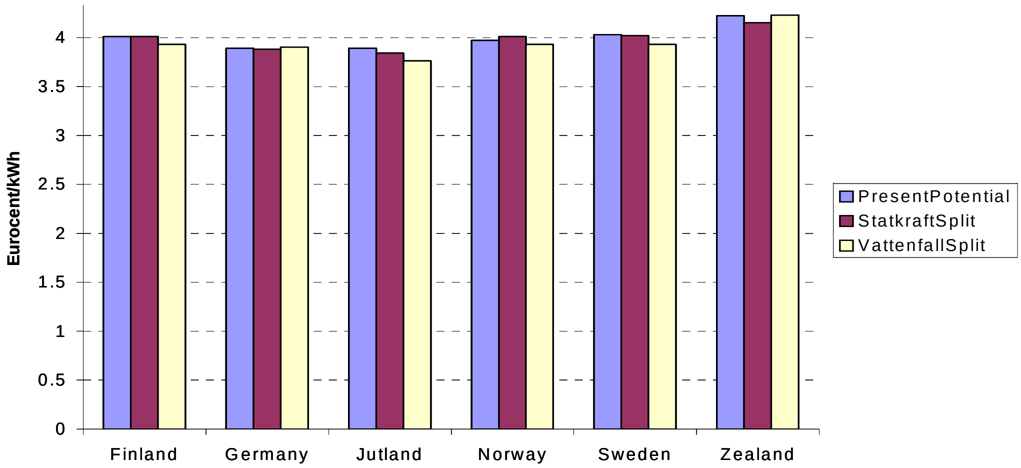
[10] Statkrafts minoritetsandel i E.ON Sverige har efter denna analys genomfördes överlåtits till E.ON.

Figur 2.3 Genomsnittliga priser med olika marknadsstruktur



Källa: Egna modellsimuleringar

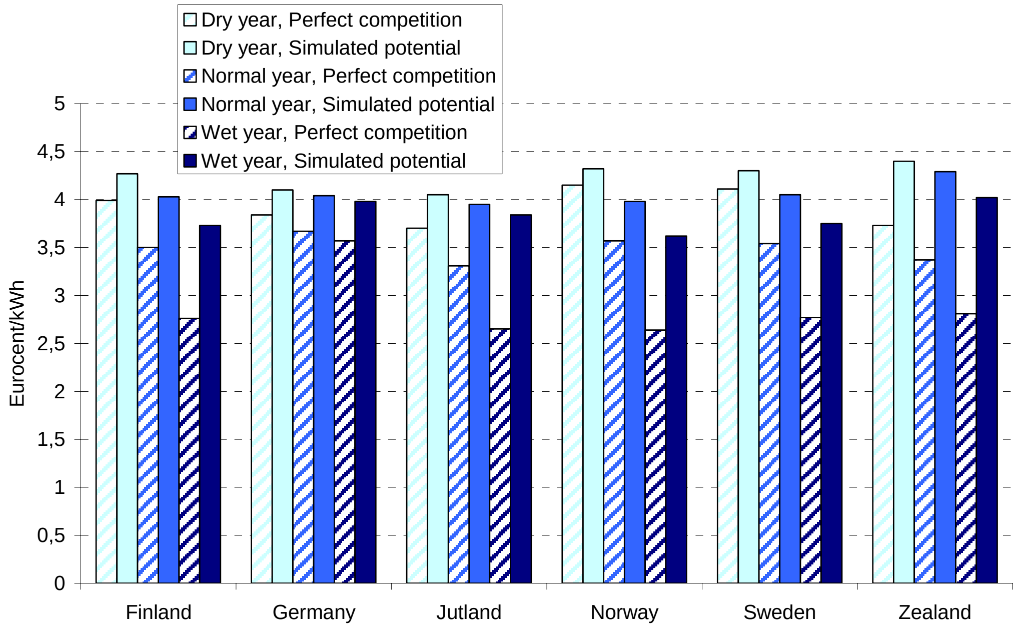
Effekter av torr och våtår

Potentialen för marknadsmakt skiljer sig åt beroende på tillgången på vattenkraft. Allmänt förväntar vi oss att det skulle vara en större potential för marknadsmakt i en bristsituation (”torrår”). Detta beror på att i ett torrår finns marknadsjämvikten på en brantare del av utbudskurvan. Det innebär att en relativt sett liten volymförändring får en stor effekt på priset. Å andra sidan, om det är en vattenkraftproducent som också står för den marginella produktionen har denna i ett torrår en mindre volym, vilket skulle minska incitamenten att utöva marknadsmakt. I tillägg är utbudskurvan trappstegsformat. Det gör att även om utbudskurvan generellt sett blir brantare och brantare gäller det inte för varje lokal del utmed kurvan. Det ”globala” mönstret behöver därmed inte återspeglas i den relevanta ”lokala” delen av kurvan. Sammantaget innebär detta att vi inte kan vara säkra på att potentialen för marknadsmakt är större i ett torrår.

Vi har därför simulerat två alternativa inflödesscenarier som definieras av att sannolikheten för att ett inflöde ska vara större respektive lägre är 25 %.

Våra modellanalyser visar på att potentialen för marknadsmakt är störst i ett våtår (se Figur 2.4), även om detta inte är ett resultat som gäller generellt. En närmare granskning av de olika lastavsnitten visar att det är särskilt i låg- och mellanlastperioder som potentialen för marknadsmakt är stor i ett våtår. Det kan förklaras med att priset under dessa perioder är mycket lågt under ett våtår. Genom att minska produktionen (främst i gamla koleldade kraftverk) kan priset pressas upp något. Under torrår utövas istället marknadsmakt främst under höglastperioden vintertid. Modellsimuleringarna visar därmed att den rena intuitionen avseende betydelsen av torr- och våtår inte nödvändigtvis håller, utan att mer noggranna analyser är nödvändiga

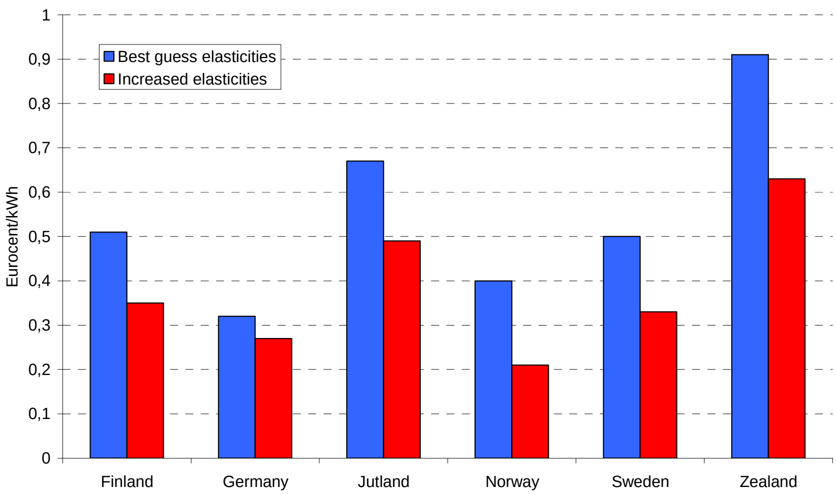
Figur 2.4 Marknadsmakt i torr- och våtår



Priskänslighetens betydelse

Resultaten är känsliga för antaganden om efterfrågans priselastictet (priskänslighet). Detta innebär för det första ett betydande osäkerhetselement i analysen, eftersom den ”sanna” priselasticiteten inte är känd. Olika studier av priselasticiteten ger skilda resultat och det är även beroende av vilken tidshorisont man ser på. Ur ett policyperspektiv är dock denna känslighet för priselasticiteten intressant, eftersom den pekar på att olika åtgärder för att öka kundernas priskänslighet väsentligen kan minska potentialen för marknadsmakt. Figur 2.5 visar påslaget över marginalkostnader dels med våra ”best guess” antaganden om priselasticiteter och dels för en situation där samtliga priselasticiteter har fördubblats.

Figur 2.5 Påslag över marginalkostnader för olika antaganden om priselasticitet



2.4 Avslutande diskussion

Sammantaget visar modellanalyserna på en betydande potential för marknadsmakt. Modellen kan överskatta de praktiska möjligheterna att utöva marknadsmakt, bland annat genom att det inte finns osäkerhet i modellen. I verkligheten finns en mängd osäkerhetsfaktorer kopplat exempelvis till tillrinning av vatten, temperaturer/konsumtionsnivå, vindkraftproduktion etc. Detta gör det svårare att i verkligheten agera strategiskt med samma precision som görs i modellen. Å andra sidan kan det finnas ytterligare möjlighet att utöva marknadsmakt i vissa enstaka topplasttimmar, vilket inte fångas av modellen. Vi har inte heller tagit hänsyn till eventuellt samordnat beteende eller karteller mellan olika aktörer.

3 Utövande av marknadsmakt på den nordiska elmarknaden

Föregående kapitel visade att det finns en icke obetydlig potential för utövande av marknadsmakt på den nordiska elmarknaden. Jämfört med perfekt konkurrenspriser kan utövandet marknadsmakt leda till prishöjningar på 11 – 27 % i de olika nordiska områdena. Denna effekt uppstår enbart genom de större producenternas ensidiga strategiska beteende (icke-kooperativt spel) och inte till följd av något kartellsamarbete.

Detta finns således skäl att noggrant följa marknaden för att upptäcka eventuellt utövande av marknadsmakt.[11] Potentialen för marknadsmakt är dock inte detsamma som faktiskt utövande av marknadsmakt.

Med hjälp av en avancerad modell för den nordeuropeiska elmarknaden har vi studerat förekomsten av marknadsmakt historiskt på den nordiska elmarknaden. Vi har valt ut tre tidsperioder: Två som kan karaktäriseras som bristsituationer och en period som är ”normal”. De två bristsituationerna är sommaren-vintern 2002/03 och sommaren-hösten 2006 och den normala situationen är sommaren-hösten 2001.

Metoden vi har använt är att simulera priserna under perfekt konkurrens och jämföra detta med de faktiska priserna. Högre faktiska priser än de simulerade priserna skulle utgöra en indikation på marknadsmakt. Det är dock viktigt att det finns en mängd andra faktorer som inte fullt ut kan fångas upp i en modell och det kan därför finns andra förklaringar än utövande av marknadsmakt.

Sammantaget ger vår analys inte stöd för att utövande av marknadsmakt har varit ett omfattande problem under de studerade perioderna. Möjligen finns det en tendens till att problemen har varit större i Danmark (Jylland) än i övriga marknadsområdet, men detta gäller främst vintern 2002/03. Det är svårt att uttala sig om enskilda timmar. Vi kan inte utesluta att det under enstaka timmar, eller vissa perioder, finns såväl en betydande potential som att marknadsmakt faktiskt utövas.

3.1 Analysansats

I den ekonomiska litteraturen finns det fler olika ansatser för att studera utövande av marknadsmakt på elmarknader. En ansats går ut på att studera det faktiska budbeteendet hos enskilda aktörer. Wolak och Patrick (1997) och Wolfram (1998) har båda använt denna ansats för studier av den engelska marknaden. Puller (2001) har använt denna ansats för den kaliforniska marknaden. En annan ansats är att se på utfallet på marknadsnivå, dvs. om marknaden som helhet sätter priser lika med marginalkostnad givet produktionskapaciteten hos samtliga marknadsaktörer. Den ansatsen har använts av bland annat Wolfram (1999), Borenstein, Bushnell och Wolak (2002) samt Cho och Kim (2007) och samtliga får resultat som indikerar utövande av marknadsmakt. Joskow och Kahn (2002) använder båda dessa metoder för att studera Kalifornien.

[11] I Norge använder tillsynsmyndigheter (NVE och Konkurransetilsynet) en övervakningsmodell utvecklad av ECON för kontinuerlig övervakning av marknaden.

På den nordiska marknaden har Johnsen, Verma och Wolfram (1999) analyserat priserna i fem prisområden i Norge och funnit visst empiriskt stöd för utövande av marknadsmakt på dessa lokala marknader vid tidpunkter då det finns betydande flaskhalsar. Hjalmarsson (2000) hittar ingen marknadsmakt på den nordiska marknaden för perioden 1996 till 1999.

Vi har i denna studie av utövande av marknadsmakt på den nordiska elmarknaden använt oss av ansatsen där vi studerar om marknadspriserna har avvikit från perfekt konkurrenspriser. För detta ändamål har vi använt en sofistikerad modell för den nordeuropeiska elmarknaden, ECON BID. Modellen är en fundamental modell som finner jämviktspriser under antagande om perfekt konkurrens. Modellen innehåller en sofistikerad modellering av vattenkraften och tar bland annat även hänsyn till start/stoppkostnader i termiska verk. Modellen optimerar användandet av vattnet över en längre tidsperiod genom att beräkna ”vattenvärden” (alternativkostnad för att producera idag istället för att spara vattnet). Marknadssimuleringen görs sedan veckovis med timvis upplösningen innefattande 168 kronologiska timmar. Det sistnämnda innebär bland annat att man kan ta hänsyn till start-stoppkostnader i termiska kraftverk. För en mer utförlig beskrivning hänvisar vi till Damsgaard, Skrede och Torgersen (2007).

3.2 Utövande av marknadsmakt med vattenkraft

Vattenkraftproducenter kan dels utöva marknadsmakt genom att minska den producerade volymen. Detta innebär dock att man måste ”spilla” vatten, dvs. inte använda den för produktion. I viss utsträckning är det troligen ett praktiskt möjligt beteende, men omfattande spill kan lätt upptäckas. Det kan dock vara möjligt för en producent att agera på ett sådant sätt att man tvingar fram en situation där spill blir nödvändigt till följd av fulla magasin (orsakade av för liten produktion). Vidare är det kostsamt att spilla vatten. Den rörliga produktionskostnaden i vattenkraft är mycket låg och den marginella nettointäkten (skillnaden mellan marknadspriset och rörlig kostnad) är därför relativt hög för vattenkraften. Denna går förlorad vid spill av vatten, vilket innebär att prishöjningen för den resterande volymen måste vara hög. Reduktion av produktion som har en rörlig kostnad nära marknadspriset innebär ett betydligt mindre nettobortfall av intäkter och prishöjningen för den resterande volymen behöver därmed inte vara lika hög. Det gör att det allmänt sätt är mer troligt att marknadsmakt genom produktionsminskningar utövas med termisk produktion med en marginalkostnad nära marknadspriset.

Vattenkraftproducenter har dock en ytterligare möjlighet att utöva marknadsmakt på och det är genom att flytta produktionen i tid. Genom att öka produktionen i en ”låglasttimme” finns mindre vatten kvar för att producera i en ”höglasttimme”. Eftersom priseffekten av en given produktionsförändring normalt sett är mindre i låglasttimmen (platt del av utbudskurvan) än i en höglasttimme (brant del av utbudskurvan) kan det vara lönsamt att flytta produktion från höglast till låglast som en del i en marknadsmaktsstrategi. Detta gäller även mellan säsonger (sommar/vinter).

3.3 Resultat

Vi har studerat tre perioder mellan 2001 och 2006. Två av perioderna kan karaktäriseras som bristperioder. Dessa är sommaren till vintern 2002/03 samt hösten 2006. Den tredje perioden, sommaren till hösten 2001, är det närmaste ett ”normalt” år som vi har sett under senare år i Norden.[12]

- Sommaren till hösten 2001 representerar ett normalt år avseende nederbörd och temperaturer. Magasinsnivåerna var något högre i Sverige än normalt medan det omvända gällde i Norge. I genomsnitt var dock nivåerna ungefär på normal nivå. Vi studerar perioden från vecka 22 till och med vecka 39.
- Hösten 2002 var extremt torr vilket bör ha bidragit till ytterligare möjligheter att utöva marknadsmakt. Sannolikheten för att det ska vara lika torrt eller torrare har i andra sammanhang bedömts till under 0,5 %. Priserna kring årsskiftet 2002/03 blev också mycket höga. Vi studerar perioden från vecka 22 år 2002 till och med vecka 5 år 2003.
- Under sommaren 2006 inträffade en mängd prispåverkande händelser. Liten snösmältning och låg nederbörd under sommaren, omfattande stängning av svensk kärnkraftproduktion och slutligen kraftiga regn framåt hösten var de huvudsakliga händelserna. Vi har studerat perioden från vecka 22 till vecka 39.

Våra resultat för de två bristsituationerna (sommaren-vintern 2002/03, sommaren-hösten 2006) ger ett produktions- och prismönster som stämmer överens med utövande av marknadsmakt. Vi har ”för hög” produktion och ”för låga” priser i verkligheten jämfört med modellen under sommaren och tvärtom under hösten/vintern.

För 2002/03 är det dock bara Jylland som det genomsnittliga priset sett över hela perioden är högre i verkligheten än i modellen, vilket indikerar att om det var en marknadsmaktsstrategi förefaller den ha varit misslyckat i de flesta marknadsområden. Modellen kan dock inte förklara de mycket höga priser som rådde kring årsskiftet 2002/03 och det gäller särskilt för Danmark (i första hand Jylland). Det kan bero på att det finns restriktioner i verkligheten som inte fullt ut fångas upp av modellen, men det kan också vara en indikation på att producenter tog chansen att bjuda in produktionen till ett mycket högt pris i den extrema situation som då rådde.

För 2006 är det genomsnittliga priset sett över hela den studerade perioden högre i verkligheten än i modellen. Ett stort problem 2006 var dock att det fanns en betydande osäkerhet kring mängden snö i fjällen (”snömagasinen”) och hur mycket vatten som skulle komma från snösmältningen. Det faktiska utfallet visade på relativt lite snö, vilket vi har tagit hänsyn till i modellsimuleringarna. Producenterna hade dock inte tillgång till samma information. Förväntningar om en större tillrinning från snösmältningen kan dock förklara den ”för stora” produktionen under inledningen av sommaren 2006. Detta gör det svårt att dra en entydig slutsats om att det har utövats marknadsmakt.

För normalåret 2001 är våra simulerade priser något över de faktiska priserna och det finns inte heller något produktionsmönster som tyder på att marknadsmakt har utövats.

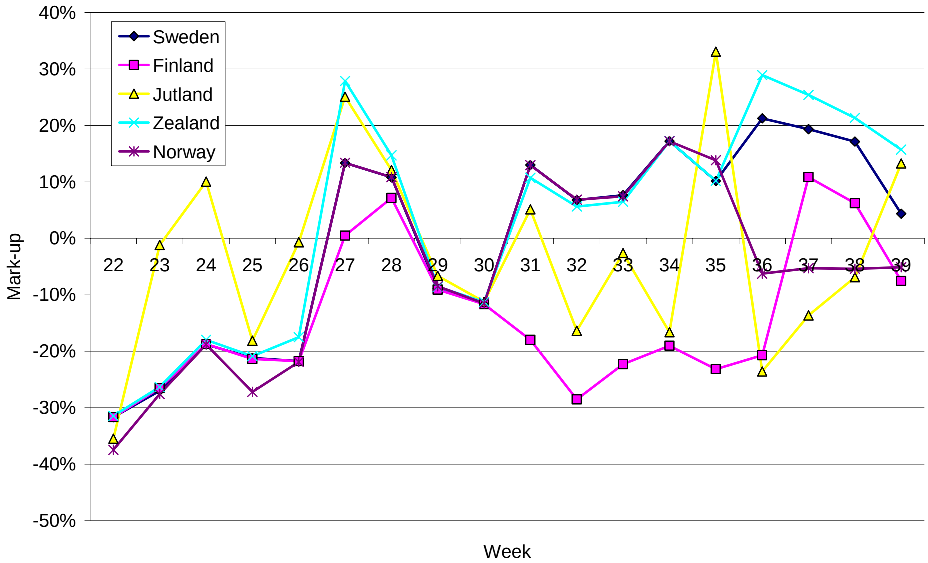
Den normala situationen: Sommaren och hösten 2001

Figur 3.1 visar det procentuella påslaget (skillnaden) mellan observerade priser och våra modellerade priser under antagande om perfekt konkurrens vecka 22 till 39 år 2001. Under de första veckorna är de modellerade priserna högre än de faktiska priserna i

[12] Med normalt avses här normal tillgång på vatten för vattenkraftproduktion samt normala temperaturer.

samtliga områden förutom Jylland. Därefter är faktiska priser på ungefär samma nivåer, eller något högre, än de modellerade priserna. Undantaget är Finland där de modellerade priserna är klart högre än de faktiska priserna. Ser man på perioden som helhet är de faktiska priserna mellan och 2 % och 16 % lägre än de modellerade priserna. I Sverige var de faktiska priserna 5 % lägre än de modellerade priserna. Resultaten ger med andra ord inget stöd för att priserna under denna period skulle ha påverkat av utövande av marknadsmakt.

Figur 3.1 Påslag (%) faktiska priser jämfört med spotpriser i Norden, sommaren och hösten 2001



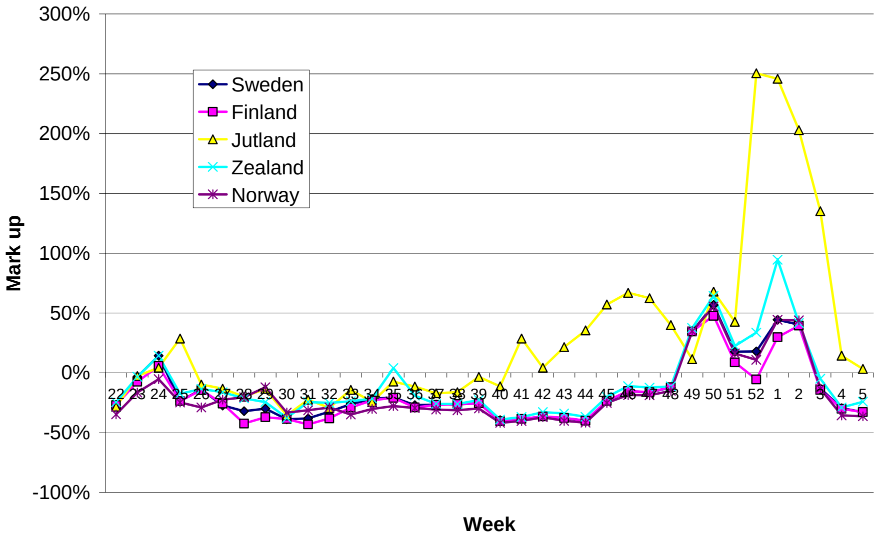
Källa: Egna modellsimuleringar och NordPool

Den torra hösten: Sommaren till vintern 2002/03

Figur 3.2 visar det procentuella påslaget (skillnaden) mellan observerade priser och våra modellerade priser under antagande om perfekt konkurrens från vecka 22 år 2002 till och med vecka 5 år 2003. De faktiska priserna ligger initialt under de modellerade priserna, men mot slutet av 2002 hamnar de faktiska priserna över de modellerade priserna. Förutom på Jylland, ligger de faktiska priserna mellan 6 % och 15 % under de modellerade priserna sett över hela perioden (i Sverige12 % under). På Jylland var dock de faktiska priserna 18 % högre än de modellerade priserna.

Den faktiska produktionen i Norge var inledningsvis högre än den produktionsnivå som modellen ger. Detta är också en viktig förklaring till prismönstret. ”Överproduktion” under låglastperioden (sommaren) för att skapa knapphet under höglastperioden (vintern) är också ett sätt att utöva marknadsmakt. Med andra ord stämmer det norska produktionsmönstret överens med en marknadsmaktstrategi. Det finns dock andra tänkbara scenarier. En möjlighet är produktion från flerårsmagasin som inte fångas upp fullt ut i modellen, vilket kan ha varit ett motiverat beteende. Det är också möjligt att modellen, snabbare än de verkliga aktörerna, fångar upp den tilltagande knappheten. Vi har i modellen i praktiken antagit perfekt information angående vattensituationen för de närmste fyra veckorna. I praktiken har aktörerna sämre information. De norska aktörerna förefaller inte heller ha vunnit på ett eventuellt utövande av marknadsmakt. De totala intäkterna var 1 % lägre för den norska produktionen givet faktisk produktion och faktiska priser jämfört med modellens produktion och priser.

Figur 3.2 Påslag (%) faktiska priser jämfört med spotpriser i Norden, sommaren till vinter 2002/03



Källa: Egna modellsimuleringar och NordPool

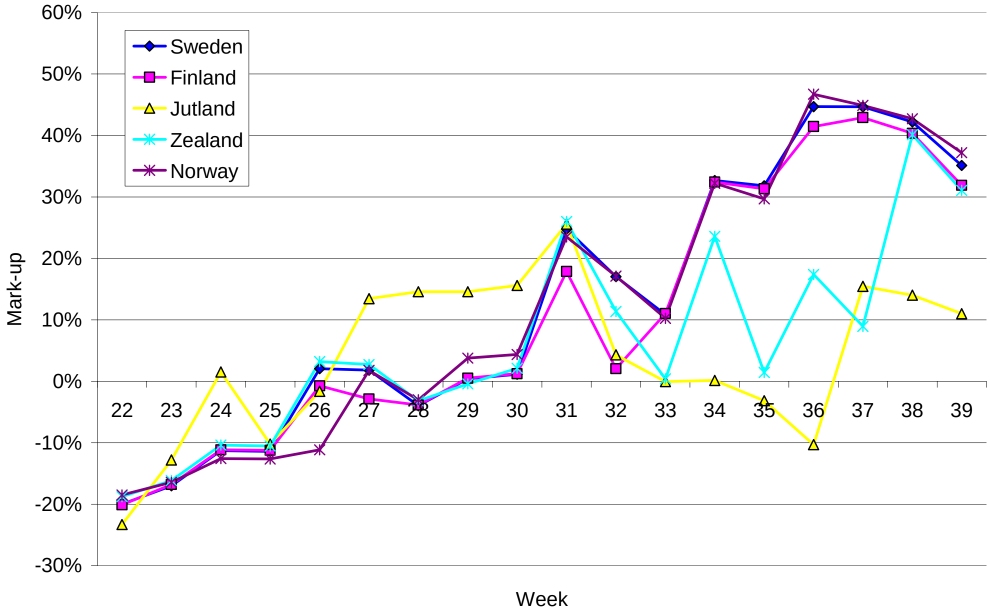
Torr sommar och lite kärnkraft: Sommaren och hösten 2006

Figur 3.3 visar det procentuella påslaget (skillnaden) mellan observerade priser och våra modellerade priser under antagande om perfekt konkurrens från vecka 22 till vecka 39 år 2006. Inledningsvis är de modellerade priserna högre än observerade marknadspriser. Vidare är de modellerade priserna mer stabila än de faktiska priserna under de första veckorna, vilket inte framgår av figuren. En anledning till detta kan vara att vi i modellen har antagit att aktörerna hade korrekt information om mängden snö i fjällen (som slutligen hamnar i magasinen). I vart fall vid snösmältningen blev det tydligt att det var lite snö. Estimaten avseende snötillgången varierar dock betydligt mellan olika analytiker och det är möjligt att vissa producenter överskattade tillgången på snö.

Från slutet av juni konvergerar faktiska spotpriser och de modellerade priserna till nästan samma nivå, men i början av augusti börjar de observerade spotpriserna öka betydligt i jämförelse med de modellerade priserna. Det gäller för samtliga områden förutom Jylland. Sett över hela perioden är de faktiska priserna ca 6 – 12 % högre än de modellerade priserna (12 % i Sverige).

Modellresultaten stämmer återigen överens med ett marknadsmaktsscenario där producenterna överproducerar under sommaren för att skapa en bristsituation senare under året. Liksom för 2002/03 är det i första hand vattenkraftproduktionen i Norge som är högre i verkligheten än i modellen. Det är dock svårt att dra definitiva slutsatser. Som tidigare nämnts är prognoserna vad gäller snötillgång osäker och prognosfel kan mycket väl förklara skillnad. Dock, och till skillnad från 2002/03, var det faktiska genomsnittliga priset högre än vad modellen indikerar och kostnaderna för kunderna i Norden blev också högre.

Figur 3.3 *Påslag (%) faktiska priser jämfört med spotpriser i Norden, sommaren och hösten 2006*



Källa: Egna modellsimuleringar och Syspower

4 Slutsatser

Vi har tre viktiga resultat från detta forskningsprojekt:

För det första finns det en inte obetydlig potential för att utöva marknadsmakt på den nordiska elmarknaden. Med hjälp av en numerisk simuleringsmodell uppskattar vi att marknadsmakt, givet dagens marknadsstruktur, kan höja priserna med mellan 11 % och 27 % i de olika nordiska marknadsområdena (14 % i Sverige). Detta visar på betydelsen av en kontinuerlig vaksamhet avseende marknadsmakt på elmarknaden. I Norge sker en kontinuerlig övervakning av detta, vilket förefaller lämpligt. Modellresultaten visar också att en minskad koncentration genom en delning av exempelvis Vattenfall eller Statkraft minskar potentialen för marknadsmakt. Modellen kan exempelvis användas för att analysera effekten på konkurrensen av företagsförvärv eller investeringar i nya överföringsförbindelser.

En viktig policyslutsats är att potentialen för marknadsmakt i hög grad är beroende av hur priskänslig efterfrågan är. Analysen visar att potentialen för marknadsmakt är känslig för antaganden om priselasticiteten. Eftersom det råder stor osäkerhet om hur stor priselasticiteten är leder det dels till en osäkerhet kring hur stor potentialen för marknadsmakt är. Samtidigt tydliggör det att åtgärder som kan bidra till ökad priskänslighet kan därmed bidra till att minska eventuella problem med marknadsmakt.

Den tredje slutsatsen är att om man studerar det faktiska utfallet på marknaden förefaller inte marknadsmakt väsentligen ha bidragit till att höja priserna. Större delen av de prisförändringar som har observerats under senare år kan mycket väl förklaras av fundamentala marknadsförhållanden under antagande om perfekt konkurrens. För båda de knapphetsperioder som vi har analyserat (2002/03 samt 2006) är produktions- och prismönster i vart fall i delar överensstämmande med det mönster man skulle förvänta sig om vattenkraftproducenter utövar marknadsmakt. Det finns dock andra potentiella förklaringar till detta utfall. Om utfallet för 2002/03 var ett resultat av att vattenkraftproducenter utövade marknadsmakt förefaller det dock ha varit misslyckat. Det genomsnittliga faktiska priset sett över perioden var lägre i alla områden förutom Jylland jämfört med modellresultaten och detsamma gällde intäkterna till producenterna. För 2006 var det genomsnittliga faktiska priset något högre än vad modellen föreslår, men skillnaderna mellan faktiska och modellerade priser är inte tillräckligt stor för att entydigt slå fast att det handlar om utövande av marknadsmakt.

När vi studerar enskilda timmar är avvikelsen mellan faktiska och modellerade priser ibland mycket stor. Dessa avvikelser sker dock både uppåt och nedåt och förefaller mer vara ett utslag av stokastiska element i prisbildningen på elmarknaden som modellen inte kan fånga upp än utövande av marknadsmakt. Det går dock inte att utesluta att marknadsmakt har varit väsentligt för att driva upp priserna i enskilda timmar. Kring årsskiftet 2002/03 noterades mycket höga priser, som vi inte kan förklara med modellen. Skillnaden mellan observerade och simulerade priser är särskilt stor i Danmark och då i synnerhet på Jylland. Detta kan bero på utövande av marknadsmakt.

Generellt sett är det mycket svårt att upptäcka marknadsmakt på en elmarknad som domineras av vattenkraft. Detta beror i hög utsträckning på att den relevanta marginalkostnaden i vattenkraftverk inte utgörs av den direkta produktionskostnaden, utan av alternativkostnaden för vattnet. Det innebär att producenterna beräknar ett vattenvärde, dvs. hur mycket vattnet är värt om man sparar det till ett annat tillfälle, som sedan bestämmer hur man ska lägga sina bud för vattenkraften. Detta vattenvärde är naturligtvis i hög grad beroende på förväntningar om framtida priser, tillgång på vatten etc. Skillnader i förväntningar kan därmed ge upphov till olika produktionsmönster utan att detta nödvändigtvis är ett tecken på utövande av marknadsmakt.

Eftersom våra resultat indikerar att det finns en betydande potential för marknadsmakt, samtidigt som det är svårt att finna belägg för att denna potential har utnyttjats i någon högre utsträckning kan man fråga sig varför det förefaller att potentialen inte har utnyttjats. Det är svårt att ge något entydigt svar på den frågan, men det finns några möjliga förklaringar.

Antingen kan producenterna (några eller alla) valt att inte utnyttja potentialen. Ett sådant val skulle kunna förklaras på flera sätt. En första förklaring skulle kunna vara att stora producenter väljer att inte utöva den potentiella marknadsmakten, eftersom de har en strategisk plan att konsolidera marknaden genom fusioner och företagsuppköp. Detta skulle kunna försvåras om det går att påvisa ett omfattande utövande av marknadsmakt. En andra möjliga förklaring är att det omfattande offentliga ägandet gör att företagen inte är fullt ut vinstmaximerande. Det är dock en tveksam förklaring eftersom det inte finns några belägg för skilda beteenden beroende på ägandet och även offentligt ägda bolag har utövad marknadsmakt såväl på elmarknaden som på andra marknader. Det kan dock vara möjligt att beteendet påverkas av de privatekonomiska incitamenten för enskilda beslutsfattare i företagen (exempelvis utformning av bonusprogram). En sista förklaring är att företagen är oroliga för upptäckt. Det kan dels leda till bestraffning för företagen, men det är även möjligt att ett omfattande utnyttjande av marknadsmakt på elmarknaden har politiska konsekvenser med en omreglering av marknaden (jmf. Californien). Eftersom elproducenternas vinster idag är höga kan de ha mycket att förlora på en sådan utveckling.

Den andra huvudsakliga förklaringen till att potentialen inte förefaller ha utnyttjats är att det är svårare i praktiken att utöva marknadsmakt än vad vår modell visar. I vår modell har producenterna perfekt information och situationen är stabil. Producenterna ”vet” i modellen hur den hydrologiska situationen kommer att vara under det närmaste året, de känner till bränslepriser och efterfrågan. Övriga aktörers beteende är också i någon mening stabilt. I verkligheten råder stor osäkerhet kring alla dessa faktorer, vilket försvårar möjligheten att utöva marknadsmakt.

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Working Paper 2007-002

Potential for Market Power in the Nordic Power Market

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Potential for Market Power in the Nordic Power Market†

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Abstract

We model the potential for market power in the Nordic power market and Germany using a numeric simulation model. The strategic behaviour is modelled by applying a supply function equilibirum (SFE) approach. Assuming non-cooperative strategic behaviour on the part of large producers prices are increased by 11-27% in the different market areas. Total output is reduced by on average 2%, but with large variation between market areas. Two scenarios including splitting of the largest producer in Sweden (Vattenfall) and Norway (Statkraft) respectively result in reduced market power, although the effect is not very large. Splitting Vattenfall reduces the mark-up in Sweden, Finland and Zealand with approximately 1/5, and less in the other areas. Splitting Statkraft has a similar but generally smaller effects on prices. The assumed price elasticity has a considerable effect on the potential for market power. This both leads to an analytical uncertainty, but it also highlights the importance of measures taken to increase the price elasticity.

Key Words

Electricity markets, market power, supply function equilibrium, imperfect competition, oligopoly

JEL Classification

D43, L13

† This paper has been written as a part of a research project on market power in the Nordic power market financed by the Swedish Competition Authority, which we gratefully acknowledge. The work has been followed by a reference group consisting of representatives of the Swedish and Norwegian Competition Authorities and we have benefited from their comments. The conclusions and views presented in the paper is the sole responsibility of the authors and do not necessarily reflect the views of the reference group or the financier.

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ECON-Working Paper no.2007-002, 21. December 2007, project no. 50830.

1 Introduction

Electricity markets are generally considered to be vulnerable to exploitation of market power, and not without reasons. First of all electricity can not be stored and the delivery of electricity is dependent upon transportation over grids. This first of this means that the market needs to clear instantaneously and that there are (more or less) separate markets for different points of time (a kWh electricity produced in one hour can not necessarily be substituted for a kWh produced in the next hour). Temporary peaks in demand can thus not be met through stored electricity, but needs to be met by more generation in a more tight market. Even relatively small producers can then – at least in principle – have market power in certain hours. The second factor – the dependence on the grids – means that the geographical market may in some situations shrink considerable due to bottlenecks.

Furthermore, the demand is generally believed to be inelastic which increases the possibility to exploit market power. The inelasticity is caused by several factors. Electricity is for some users a good with limited substitution options. Heating can be done through the use of other energy carriers (e.g. bio, district heating, oil, gas), but such substitution is, at least in a short-term perspective, contingent on that investments in alternative heating equipment has already been made. For temporary high prices (a few hours) the electricity use for heating can be shifted somewhat in time, but otherwise the consumers are left to reducing the comfort (for household heating) or when electricity is used as an intermediate good take actions that affect the production (for industry). For other uses, such as lighting, the alternatives are usually in practice non-existent. Furthermore, institutional and contractual factors often limit the pass-through of short term high prices into end-user prices (measurement, fixed price contracts etc).

There are also examples when market power has clearly been exploited. The Californian electricity crisis is perhaps the most apparent case. In the UK market following deregulation market power was an issue with only two price setting firms. In the Nordic market, the abuse of market power in western Denmark has been proven for the period 1 July 2003 – 31 December 2004 and the Danish competition authority are currently reviewing cases for both western and eastern Denmark for 2005.

The Nordic market is one of the most well-developed electricity markets in the world. It contains some of the pioneer countries in electricity market deregulation and the world's first international electricity exchange (Nord Pool). The enlargement of the market diluted market power in the Nordic market, but over time the concentration levels have increased due to mergers. Looking at the Nordic market as a whole the market concentration may not be that high, but given that electricity markets are vulnerability of electricity markets there are still grounds for concern.

In this paper we study the potential for market power in the Nordic electricity market using a numerical model. The market power model is built around a simplified version of ECON Classic, which is a proprietary model of ECON that has been developed for a period of more than 15 years and used primarily for long-term price forecasting and policy analysis.

The market power model simulates strategic behaviour on the part of the large electricity producers in the Nordic region and Germany. We find that there is substantial potential for exploitation of market power.

2 Literature

2.1 Modelling market power in electricity markets: the theoretical background

Wholesale electricity is a homogenous good implying that market power should be modelled using a model of homogenous good. The two traditional models of market power are the Cournot and Bertrand, which differs in terms of which strategic variable the firm uses. The Cournot model is generally seen as the more reasonable model when firms have to commit to a certain quantity in advance, such as choosing the capacity,[1] while the Bertrand model might be more reasonable when firms have to commit to prices (or prices are difficult to adjust). For electricity markets it has become common to model market power using so called supply function equilibrium (SFE) models.

2.1.1 Classification of models

Ventosa et al (2005) classifies electricity market models into three groups. The first group are optimization models for one firm, which focus on the profit maximization problem for one firm and the market price is exogenous. These types of models are useful for e.g. short-term hydrothermal modelling and unit commitment, since they are able to deal with difficult and detailed problems.

The second class of models are market equilibrium models where all firms are considered. Market power can then be modelled using e.g. Cournot equilibrium or SFEs. These models are more suitable for long-term planning, where the response of all competitors is more important than the detailed modelling capability.

A third class of models are simulation models, which are an alternative to equilibrium models when the problem under consideration is too complex to be addressed under within a formal equilibrium framework. While equilibrium models are based on a formal definition of equilibrium[2], the agent's strategic decision rule is in simulation models usually represented by a set of sequential rules. Simulation models have the advantage of flexibility and it is possible to implement almost any kind of strategic behaviour.

According to this classification our model can be classified as a simulation model. This type of model has been chosen in order to be able to represent the physical characteristics of the Nordic power system in relative detail. This does for instance include non-differentiable marginal costs with different technologies (step-wise linear) and transmission constraints between areas.

[1] Kreps and Scheinkman (1983) shows that in a two period game when the firm first chooses the capacity and then compete in prices results in the Cournot outcome.
[2] Which are expressed mathematically as a system of algebraic or differential equations.

2.1.2 Cournot and SFE models

The most common approaches to model market power in wholesale power markets are Cournot (compete in quantities) and SFEs (compete in both quantities and price). Kahn (1998) concludes that the Cournot approach is more flexible and tractable and it has attracted more interest for this reason. However, SFE models better captures the actual bidding behaviour of the firms.

There are several contributions using Cournot models. Andersson and Bergman (1995) used a static Cournot model to assess the potential for market power in a deregulated Swedish electricity market. In the EMELIE[3] project a static game-theoretic computational model (the EMELIE model) a model for the German electricity market (Kemfert, 1999; Jenfert and Tol, 2000; Lise, Kemfert and Tol, 2003) has been extended to cover eight European countries. This model integrates different assumptions about market structure and strategic behaviour; perfect competition and Cournot and Stackelberg oligopoly. The problem with the static models is that in those models the market is analyzed as a one-shot equilibrium and that dynamics in the market is lost. This is particularly of importance when analyzing market power with hydro power, since this is usually executed through shifting the production over time rather than reducing the total output. Furthermore, if the market is analyzed as a one-shot equilibrium the modelling will not capture differences in the market depending on variations in load (hourly demand). However, Cournot models can of course be used in more advanced models. Scott and Read (1996) use a model where at each stage the hydro optimization problem is superimposed on a Cournot market equilibrium. Bushnell (1998) has a similar model for the California market. There are also a number of other studies using different methods with more advance Cournot models. Since the generators' strategies are expressed only in terms of quantities in Cournot models (and not in bid curves) the models become highly sensitive to demand representation and the resulting prices are typically higher than what is observed in reality.

[3] Electricity Market Liberalisation in Europe, for more information see http:/www.uni-oldenburg.de/speed/english/projects/emelie.htm

SFE models under (demand) uncertainty were first introduced by Klemperer and Meyer (1989). There are now numerous examples of SFE models and we will not review them here. In SFE models it is assumed that the producers submit supply functions simultaneously to a uniform-price auction in a one-shot game. Klemperer and Meyer furthermore dealt with a situation with identical suppliers (symmetric system). Admissible supply functions should be monotonically increasing. The motivation to use SFE models for the electricity market is generally found in the argument that the SFE offers a more realistic view of how electricity markets function, where bid rules in some cases require suppliers to offer a price schedule that is applied all through a day, rather than to simply provide a series of quantity bids. To find the SFE each producers submit a supply function such that for each demand outcome the market price is optimised with respect to its residual demand. The mark-up will be inversely proportional to the elasticity of the residual demand for all outcomes, which depends on the supply functions of all the competitors. The SFE is thus given as the solution to a system of differential equations.

SFEs are attractive for modelling market power in electricity markets particularly considering the strong dependence on demand elasticity in the Cournot models can make such models unreliable.

The application to electricity markets was first made by Bolle (1992) and Green and Newbery (1992). For tractability reasons increasing focus has been on linear SFEs with linear or affine marginal cost curves. Green (1996) used a linear SFE to with linear marginal cost facing a linear demand curve with invariable slope over time giving an SFE expressed in affine supply functions. Baldick, Grand and Kahn (2004) offer a generalization of the model in Green (1996) with an application to subsequent changes in the horizontal structure in England and Wales. Many SFE models use a marginal cost function with a zero intercept or assume that all have a common intercept. Baldick, Grand and Kahn generalize this and use an affine approximation to a piece-wise linear marginal cost curve, which matches the marginal cost both at full and zero production. They also propose an ad-hoc approach to constructing piece-wise affine supply curves.

The majority of the SFE literature considers smooth, twice continuously differentiable supply functions. For electricity markets this assumption may be questioned, due to the typical cost structure in electricity generation. Von der Fehr and Harbord (1993) have a model incorporating quantity discreteness, and this model has later been used in several papers. These models are often very difficult to solve for uncertain demand and situations with supply functions with more than one step or more than two bidders. Furthermore, they often do not have pure strategy equilibria and finally in reality there is often discreteness in both price and quantity.

However, integrating SFEs into non-symmetric cases is not easy and can for example yield supply curves that are not always monotonically increasing (or even always monotonically declining supply functions). Baldick and Hogan (2002) show that if firms have heterogeneous cost functions and capacity constraints the differential equation approach to finding the equilibrium supply function may not be effective since it fails to yield non-decreasing supply functions, or that the equilibria are unstable. They analyze the non-decreasing constraints and characterize piece-wise continuously differentiable equilibria. Stable equilibria are found iterating in the space of allowable supply functions.

A basic weakness of SFE is multiplicity of equilibria, which reduces the predictive power of the models. For symmetric producers with smooth supply functions and non-positive minimum demand one can show that only symmetric equilibria exist, but this solution will include an integration constant. The latter implies that there is a continuum of symmetric equilibria bounded by the Cournot and Bertrand equilibria. The least competitive SFE yields Cournot prices at peak demand, but off-peak prices below the Cournot prices, while the most competitive SFE yields competitive prices at peak demand but higher than competitive prices at off-peak. Affine SFE will result in an intermediate solution and are typically closer to prices that are observed.

Capacity constraints tend to limit the range of equilibria. Green and Newbery (1992) describe the conditions for uniqueness in a case when the capacity constraint is so tight that the price at peak demand in the SFE is as high as the price under Cournot competition. Baldick and Hogan (2002) find that the range of equilibria is less likely to be problematic when there are moderately tight capacity constraints and price caps. Holmberg (2006) also shows that with a positive Loss-of-Load probability there is a unique symmetric SFE. Baldick and Hogan (2006) show that all SFE between the least and most competitive, except for the affine SFE, are unstable and thus unlikely to be observed in reality. Genc and Reynolds (2005) formulate a SFE model in which generation capacity constraints can cause some suppliers to be pivotal.[4] This reduces the set of SFE. When excess capacity falls or the load ratio rise the set of SFEs becomes smaller and it is the most competitive equilibria that are eliminated.

Shoshansi and Oren (2007) provide an analysis of how good supply function equilibrium models are to predict actual bidding behaviour. They compare the optimal bid curves from a complicated general-form SFE model which explicitly takes the contracted supply positions of each generating firm and allows for uncertainty in the demand for balancing energy, with the actual bidding behaviour of the firms. The conclusion is that bidding behaviour of the large (strategic) generators matches the theoretical optima rather well, while for smaller generators this is not the case. This implies that for a large segment of the market the behavioural assumptions and predictions of SFE is not in line with the actual behaviour of the market participants, and one may question whether this type of complicated SFE models are too complex and whether they give any better behavioural or price predictions than simpler models. E.g., linear SFE models give fairly accurate price predictions, while they cannot capture complicated bidding behaviour. Conventional Cournot-type models may also be sufficient in terms of determining equilibrium prices.

Wolfram has analysed the English market in two papers (Wolfram 1998, 1999) and claims that supply function equilibrium models do not capture the spot market particularly well and that the prices also have been lower than what these models predict.

SFE models do represent an explicit obligation to bid consistently over an extended time horizon (e.g. a day or a longer time period). If the suppliers instead

[4] A pivotal supplier is a supplier which is necessary to meet market demand. Such supplier can unilaterally

have the possibility to bid unique supply curves for each realization of demand, they can adapt the bid in such a way so that the final outcome is equivalent to the Cournot equilibrium.

Conceptually does thus the SFEs capture the bidding behaviour in a more accurate way than Cournot models and Cournot models seems to generate too high prices compared with what is observed. On the other hand it may be questioned whether complicated SFEs add much predictive value, at least in comparison to simpler SFE specifications (linear of affine models). The literature reveals the huge difficulties in using SFEs particularly in combination with accurate descriptions of the physical market that is analyzed.

In order to capture the complexity of the market, including heterogeneity of market agents, non-differentiable marginal cost curve, physical restrictions we have chosen a simulation model, i.e., we do not mathematically solve for an equilibrium but employ a search algorithm to find a stable solution. Furthermore, the bidding strategies are restricted to a linearly increasing mark-up on the marginal costs. Halseth (1998) used a similar approach, although with a different algorithm, and applied a special case of a SFE model to the Nordic power market. In Halseth’s model the producers’ supply curves are characterised by a constant mark-up relative to the short-term marginal production cost. In later versions of the model this set-up was changed to a linearly increasing mark-up. Following Green and Newbery (1992) the producers do no face uncertainty with respect to demand, but face a range of demand levels to which a single supply curve must be applied. Halseth’s model is built around the same, although later developed and expanded, model for the Nordic power market as we have used here (ECON Classic).

3 The model

Our model is an application of a supply function equilibrium model based on a numerical search algorithm. The model is built on the framework of ECON

move the market price substantially by withholding a small amount of capacity.

Classic, which is a fundamental model for the European power market developed over a period of more than 15 years. The model originally covered the Nordic power market and has been developed and made more sophisticated and during the last years the geographical coverage has been extended to Europe. This model is used both in research and for commercial applications to e.g. provide long-term price prognosis. The model is designed for modelling long-term market developments and incorporates a detailed description of generation, transmission capacities and demand. In order to be able to capture the additional complexities of modelling market power, this model has been adapted and in certain aspects simplified. For the market power simulations, the model has been adjusted to a short term model. There are two aspects which have been changed: the price elasticity has been reduced since short term elasticity is lower than long term elasticity. Furthermore, there are no endogenous investments. The mathematical programming components are implemented in GAMS.

The basic model (perfect competition) is an equilibrium model, based on the assumption of perfectly competitive markets. This is captured in mathematical terms by the model maximizing the total surplus areas[5] under a number of basic constraints. Such constraints are, for example, that demand has to equal supply at all times, transmission constraints, CHP generation profiles etc. To analyze market power the model is adjusted to take into account strategic behaviour on the part of large producers. The modelling of market power builds on the concept of supply function equilibrium, i.e. the producers bid in their production capacity at a cost and the model searches for an equilibrium which is such that no producer can increase their net income (volume time price minus short term production cost).

A mathematical specification of the both the version of ECON Classic which was the starting point of the market power model as well as the marked power model itself is included in Appendix A.

[5] Taxes are treated as costs and not income distribution.

3.1 Specification of the model

3.1.1 Specification of supply

The Nordic power market is characterized by a mixture of hydro and thermal power. Norway is almost completely dominated by hydro power, and in Sweden almost half of the electricity comes from hydro (47% in 2005), while the other half comes from nuclear power (45% in 2005). Finland has a more varied generation structure with 1/3 coming from nuclear, close to 50% from conventional thermal (most of it CHP), and 20% from hydro. In Denmark 80% comes from conventional thermal (most of it CHP) and close to 20% from wind. Most of the conventional thermal generation comes from co-generation (public and industrial CHP). This results in a generation structure where the north-western part of the market (northern Sweden and Norway) is dominated by hydro while the southern and eastern parts (Denmark, south Sweden and Finland) are dominated by thermal generation.

Table 1. Electricity generation (2005) and installed capacity (31 Dec, 2005) in the Nordic market (excl. Iceland)

	Generation, TWh	Share of generation	Capacity, MW	Share of capacity
Hydro power	222.2	56 %	47.4	52 %
Nuclear power	91.8	23 %	11.6	13 %
Other thermal	72.7	18 %	28.2	31 %
of which CHP	*66.1*	*17 %*	*18.7*	*20 %*
Wind	8.2	2 %	4	4 %
	394.9		91.3	

Source: Nordel

The Nordic power system is thus a “hydro-thermal-wind” power system, and when modelling the Nordic power market it is thus necessary to take into account both the specific characteristics of a hydro dominated system and the characteristics of a thermal dominated system.

The model includes relevant data for existing generation technologies and fuel and other operational costs. Conventional thermal capacity is called into production whenever market prices cover marginal bids. The generation set is specified at the plant type level. Each plant type has several general technical properties (such as costs) that are constant, and other technical properties (such as capacities and efficiencies) that differ by country. The value of specifying individual plants lies within the possibility to model part load efficiency and start up costs. This requires the use of a different solver and requires a substantial increase in complexity and computation time.

Wind production and CHP production are represented by production profiles based on statistical data. Regarding CHP, the model allows advanced CHP modelling, and extraction and backpressure technologies are modelled separately.[6] The latter category is further divided into public and industrial CHP.

In the context of the Nordic power market or other markets with large hydro reservoirs, it is crucial to represent hydropower with reservoirs in an adequate manner, i.e., to take into account the system's ability to store water over longer periods of time. For example, while inflows peak in the summer when the snow melts and in the fall when precipitation comes in the form of rain, demand peaks in the winter. Hence, hydropower generators store water and, at any given time, will supply according to current reservoir levels and expectations about future inflow and prices. In order to capture this feature, the model optimizes the use of water over the year, taking inflow and reservoir constraints into account.

Transmission Structure

Cross border transmission is modelled from an economic standpoint (rather than via a physical load-flow approach), with each connection from any one region to any other region having a specified (linear) loss, cost, availability, and capacity.

In general, the model allows three types of inter regional transmission:

- Normally the transmission is price-based, i.e. transmission between regions is based on price differences (the price includes losses and transmission fees).

[6] Backpressure plants are characterized by a fixed relationship between heat and electricity generation. Extraction technologies, on the other hand, are to a certain extend flexible in this respect, and the heat generation gives constraints on the electricity generation, without determining it.

- The transmission can be fixed between regions based on contracts between the regions (for example Finland and Russia).

- Transmission can be a combination of the price-based and fixed. In this case the model allocates the line capacity required for the fixed trade flows to the fixed trade, and only the remainder of the capacity is available for price-based trade.

It is assumed that there are no transmission bottlenecks within a given country.[7] Internal transmission and distribution losses, however, are accounted for by using linear loss functions.

3.1.2 Demand

Demand is specified as a Cobb-Douglas demand function with different price elasticities for up to five demand groups. The five groups are households, power intensive industry, service industry, other industry and electric boilers. There is significant uncertainty about the price elasticities for power demand. Research reports indicate highly variable numbers, partly due to lack of data and use of different statistical methods. The values used in the model (base case) lie in the range from -0.2 (the service sector) to -0.8 (dual boilers which are possible to run on multiple fuels – this sector is however only represented in Norway and Sweden). Households are assumed to have a price elasticity of -0.4 in all the five countries represented in the model. The power intensive industry is supposed to have a fixed demand which is only reduced for very high average prices.

Furthermore, the user specifies demand shapes over the year and over the day (by using load blocks) for each of the demand groups. Within each season, the demand is supposed to respond to average price over the three load blocks. This is because the majority of consumers are not metered hourly and hence have incentive just to respond to the average price.

For each demand group, the user also specifies mark-ups, taxes, distribution costs, VAT levels etc.

[7] Jutland and Zealand are treated as two separate countries in the model.

3.1.3 Time Structure

Simulations in the market power model are run on a two-level time resolution. The simulation period can be divided up into one or more time periods, such as quarters, months or weeks. Each period is then divided up into a number of load blocks. The load blocks represent the varying load levels experienced in each period and generally correspond to times of the day, such as night, weekend day, evening, day-time peak, etc. Unlike the periods, the load blocks are not sequential (that is, load block 2 does not follow load block 1 in time for example).

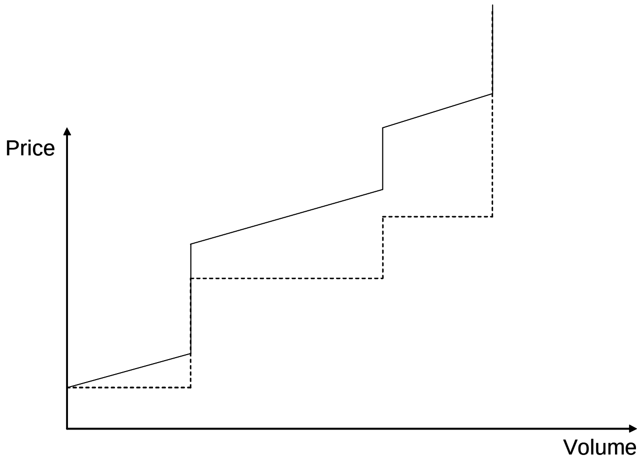
Both the period and load-block resolution are user-definable. The user simply specifies the length of each period (which can be of unequal length), and the hours in a typical week that are mapped to each load block, and ensures the data corresponds to these definitions. We have used two periods (winter and summer) and three load blocks in our market power simulations.

3.1.4 Bidding and strategic behaviour

The largest producers are assumed to bid in their production capacity at short term marginal costs plus a mark-up which increases linearly from zero with production level. Hence, the mark-up can be described with only one parameter – the angle of the mark-ups. A bid for an associated short run marginal cost curve is shown in Figure 1.

The mark-up is differentiated between regulated hydro production and thermal production. The reason for this separation is the different role the mark-up has for regulated hydro power versus other technologies. The short run marginal cost of regulated hydro power plants consist of direct production costs (wear and tear of the equipment) plus a water value reflecting the possible future income by storing water in the reservoir. The marginal water values are implicitly calculated in the model in the optimization algorithm. The consequence of this is that, as long as the producer is not spilling water, it is the relationship between the mark-ups which are important for regulated hydro power whereas it is the direct mark-up which is important for the other technologies. This is described in the appendix A.

Figure 1. Bid from one particular producer in one area with the underlying short run marginal cost curve.



In addition to the separation between technology groups, the mark-up for each producer is supposed to vary with geographical area, season and load block. There will hence typically be different mark-up in peak load than in base load. Furthermore, e.g. Vattenfall may have a different mark-up in Jutland than in Sweden.

Taking computational burden into consideration it is not practically possible to treat all producers as strategic. The largest companies are exogenously defined as potentially strategic whereas the remaining companies are defined as a competitive fringe and bid according to marginal cost.

The model does not restrict the player to bid identically in different time segments (seasons and load blocks) as is usually the case for SFEs.

3.1.5 The simulation algorithm

Description of the simulation algorithm is divided into two. Directly below is an overview of the model. In the sub-section below is a description of how the simulation algorithm finds alternative sets of mark-ups to use.

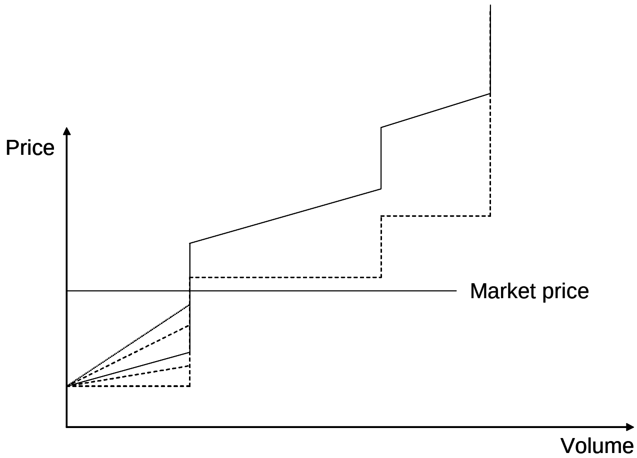
The simulation algorithm starts with one (arbitrary) market solution. This may for instance be the perfect market solution where all the mark-ups are zero. Or it can be any other market solution based on any set of mark-ups. Thereafter it can be described shortly as:

- For a number of iterations:
  - For each company, for each geographical area and for each technology group (regulated hydro versus all others):
    - Calculate the profit for the relevant company for many (96) different sets of mark-ups for that particular company, geographical area and technology group. A set of mark-ups consists of 6 different mark-ups, one for each time segment. All other mark-ups (other companies, areas and technology groups) are kept constant.
    - Choose the set of mark-ups that gives the highest profit for the company considered. The profit is defined as the price minus short run production costs multiplied with production level. The profit includes profit in all time segments, geographical areas and technology groups. It also includes a share of the profit in companies where the relevant company has minority owner shares.
    - If the set of mark-ups chosen is an “extreme set”, increase the “grid size” for that company. If the set of mark-ups chosen is not an “extreme set”, decrease the grid size for that company. This is further explained in the description of the search algorithm below.

Finding the possible mark-ups

The simulation algorithm lets one producer at a time change their bids and see if they in this way can increase their bids. It is however not trivial to find alternative sets of mark-ups. The reason is the step wise linear bid curve. In Figure 2, a situation is shown where it is possible to change the slope (mark-up) dramatically without changing the market solution at all. All the different bids shown with different slopes in the first segment of the bid curve give the same market price. In other situations, the effect of only a small change in the slope can give very large changes in the market result. This will typically be so if the production level is large and the price is actually set by the bid curve of this particular producer.

Figure 2 *Different bids give the same market solution and hence profit*



To overcome this problem, the simulation algorithm starts by changing the produced *volumes* instead. It changes the volume (produced by one company in one geographical area by one of the two technology groups) in one time segment at a time. There are hence tests for 6 different time segments in each round (2 seasons times 3 load blocks). For one particular time segment, the production level from the particular producer is both reduced by introducing restrictions on the allowed level of production (further described below). This ensures that we obtain different market solution. The model tests eight levels below the original production outcome and eight levels above.

Let the original production volume be *V* and let the restrictions on the maximum and minimum production levels in the search algorithm be defined by a percentage *f* of *V*. We then search for the volume that maximizes the profit given the bids provided by all other bidders:

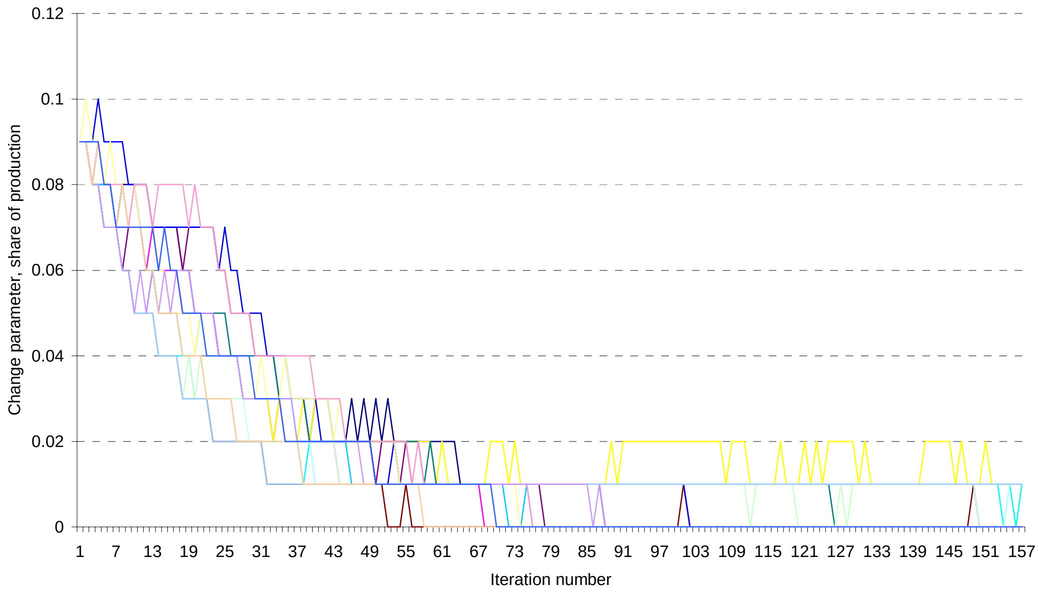
$$\underset{k}{Max}\left[\pi_i\left(V_i(1+kf)\middle|B_{j\neq i}\right)\right],$$

where $k = \{-8,8\}$ and *B* is the bids provided by all other bidders.

This gives a total of 96 alternative market solutions (6 time segments times 16 production levels). For each of the 96 production levels a set slopes for the mark-up is calculated which gives exactly the same market solution (and hence exactly the same profit for each company). There are hence calculated 96 different sets of mark-ups for the actual producer in the relevant area. The mark-ups of all other producers are kept constant.

For the next round of iterations *f* is increased if the profit maximizing volume comes from any of the two extreme sets: *V*(1-8*f*), *V*(1+8*f*), for any of the time segments, otherwise *f* is decreased. Figure 3 shows the development in percentage for the various companies. Please note that the percentages are output from the model with only two decimals and that the curves hence look more erratic than reality.

Figure 3. Development of percentage (f) for the different companies over the iterations



Source: Output from model simulations

3.2 Robustness og the simulation algorithm

Strictly speaking the model does not find a Nash equilibrium, i.e., a solution in which no player can increase its profit by unilaterally changing its behaviour. This may be either because a Nash equilibrium does not exist or because the model simply is not able to find it. The model does however find solutions that somewhat loosely can be characterised as "stable", i.e. where there are only small price changes over a large number of iterations and without a clear trend.

Examples are given in Figure 4 and Figure 5 which show the development of the Jutland and Swedish prices respectively over the iterations.

The figures show the development of average prices with two different model runs. One of the simulations was started with zero mark-up, i.e. with the perfect competition solution. The prices are seen to increase from the starting point. The other simulation is started from a random position where average prices are fairly high and then decrease towards the stable situation. The two figures show the price development for the price at Jutland and Sweden respectively. The price at Jutland is shown since it is the least good match. Still we can see that the two prices become fairly close.

Figure 4 Development of the price on Jutland with number of iterations in model simulation.

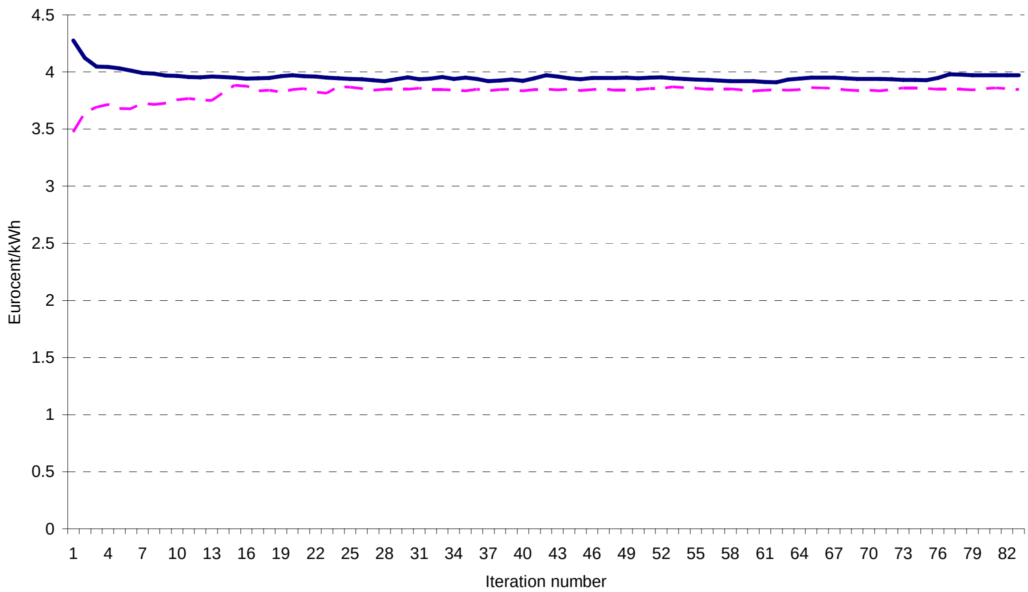
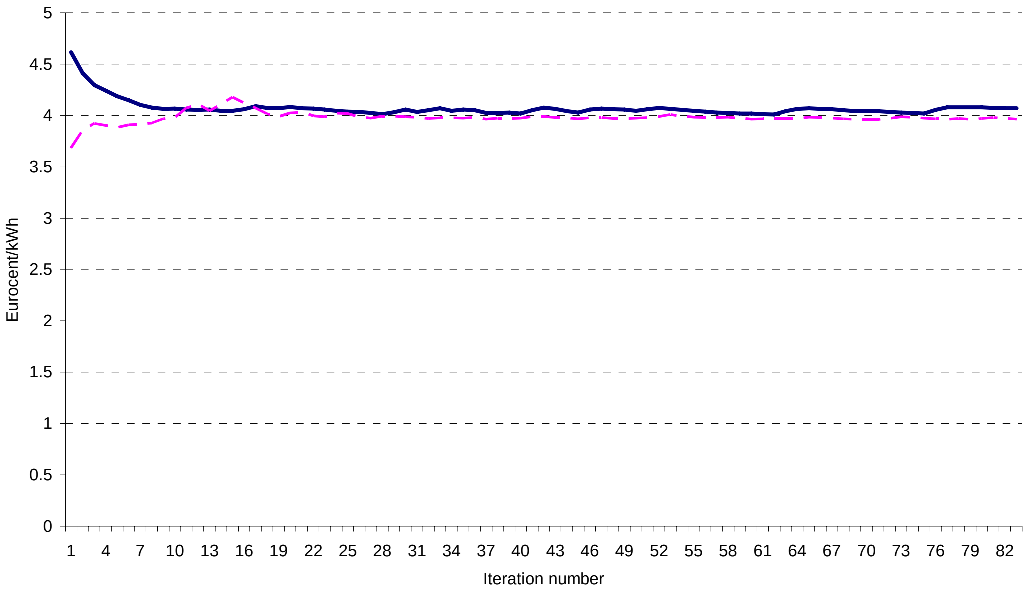


Figure 5. Development of Swedish prices with number of iterations in model simulation.



The following can be observed:

- The model finds the same price level independently of starting point. It can however not be guaranteed that this will always be the case.

- The degree of accuracy in market power simulations is smaller than in perfect competition models. Hence small differences in prices between scenarios should not be interpreted as definite signs of more or less market power. Rather, when the differences are small, it should be taken to indicate that there are not significant differences in the degree of market power.

4 The potential for market power: numerical results

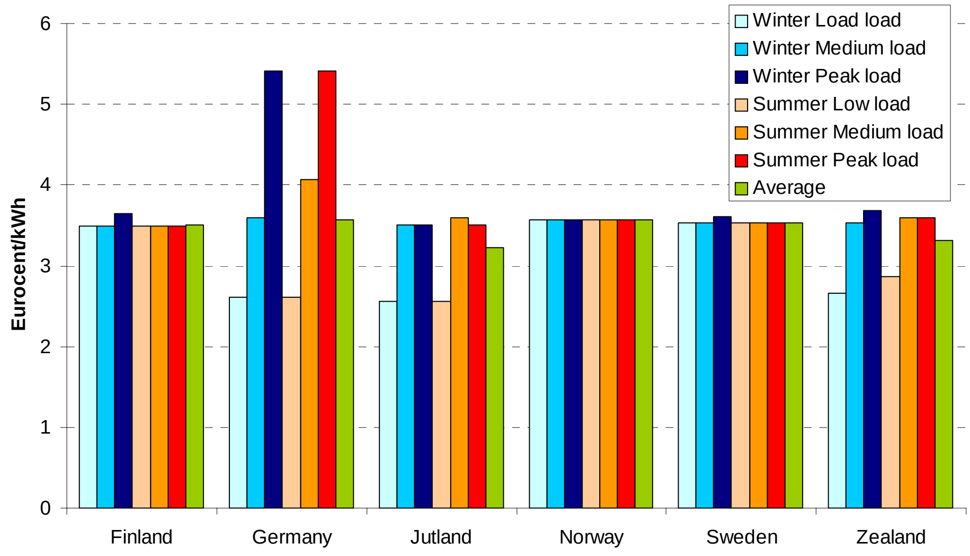
We have used the model to simulate prices in the Nordic power market for different scenarios. As a benchmark we first present the results assuming perfect competition (i.e. price taking behaviour on the part of the producers). We then present three different market power scenarios assuming strategic behaviour on the part of the large producers in the Nordic market. For computational reasons it is not possible to let all producers act strategically, and it would not to any significant degree improve the precision of the model to do that. In the current simulations we have assumed that Vattenfall, E.ON, Fortum, Statkraft and DONG are strategic players in the Nordic market and that Vattenfall, E.ON, RWE and EnBW are strategic players in the German market.

The three market power scenarios presented represent the current market structure and two scenarios in which Vattenfall and Statkraft are split.

4.1 Perfect competition

The power market has been simulated with the assumption of perfectly competitive behaviour, i.e. all producers are assumed to bid in their full production capacity at short run marginal costs. The resulting prices are shown in Figure 6. The simulated average prices assuming competitive pricing is in the range from 3.2 eurocent/kWh (Jutland) to 3.6 eurocent/kWh (Norway and Germany). The regional price differences are hence relatively small within the Nordic region. However, the price structures differ substantially between the regions. There is no price difference between the time segments in Norway, 0.1 eurocent/kWh in Sweden, 0.15 in Finland, approximately 1.0 eurocent in Jutland and Zealand and 2.8 eurocent in Germany. This reflects the technology mix in the different regions – the higher the share of regulated hydro power, the smaller the price differences between the time segments. This is because the regulated hydro power systems are energy constrained whereas the thermal power systems are capacity constrained.

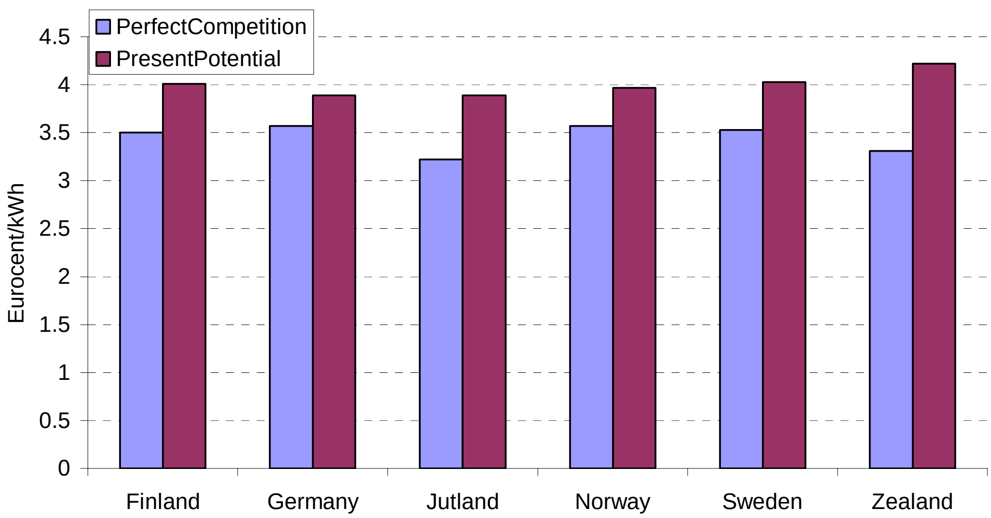
Figure 6. Simulated prices with perfect competition



4.2 The potential for market power in the present market

The model has been used to analyze the potential for price increases due to market power in the Nordic power market in the present situation, i.e. with the present demand level, production capacities, ownership structure etc. The simulated hourly average prices are shown together with the simulated prices for the case with perfect competition is shown in Figure 7.

Figure 7 Simulated average prices with competitive pricing and with strategic behaviour of large power producers, eurocent/kWh



Assuming strategic behaviour on the part of large power producers the average price increases to between 3.9 eurocent/kWh (Jutland and Germany) and 4.2 eurocent/kWh (Zealand). In Finland, Norway and Sweden the simulated prices are approximately 4.0 eurocent/kWh. According to the simulations, strategic behaviour on the part of large power producers increases average prices with 0.3-0.9 eurocent/kWh. The lowest price increase is in Germany and the highest in Zealand. The model simulations thus reveal a significant scope for market power with price increases due to strategic behaviour (compared with perfect competition) in the range 11-27 per cent in the Nordic region (9% in Germany).

Table 2. Simulated average prices with competitive pricing and with strategic behaviour of large power producers, eurocent/kWh

	Jutland	Zealand	Finland	Germany	Norway	Sweden
Perfect competition	3.2	3.3	3.5	3.6	3.6	3.5
Market power, current structure	3.9	4.2	4.0	3.9	4.0	4.0
Difference	0.7	0.9	0.5	0.3	0.4	0.5
Difference, %	22%	27%	14%	9%	11%	14%

The overall production in the region is reduced with almost 14 TWh (or 1.5 % of the total generation). The high prices cause a significant reduction in power consumption: 11.6 TWh. The largest reduction of the consumption in absolute term is found in Germany with 4.8 TWh. Relative to the consumption in perfect competition, the reductions are in the range 0.9 % (Germany) to 2.6 % (Zealand). The remaining power deficit is met by reduced net export from the region to surrounding areas, primarily to the Netherlands.

The largest reduction in generation in absolute terms is in Jutland (5.6 TWh or 18.3% of the generation in perfect competition), Germany (4.3 TWh or 0.7 %) and Zealand (4.1 TWh or 22.8 %). In Sweden the reduction is 0.4% while the production level is approximately unchanged in Norway and in Finland it is actually increased with 0.3 %. This reflects both the ownership structure, but also very much the technology mix. It is primarily production in (relatively) old coal fired power plants which is reduced (9.8 TWh in condense units and 6.3 TWh in CHP plants of extraction type). This is because it is generally not very profitable to run these plants – the prices are typically equal to or only marginally above the short run marginal costs of these plants. There is an increased production in

Finnish gas fired power plants of 3.5 TWh by the competitive fringe. Furthermore, hydro power production is reduced with 0.12 TWh, primarily by Vattenfall.

There are very small short run marginal costs in hydro power plants. It is hence costly to reduce the yearly production by spilling water. But the hydro power producers have the potential to shift the production pattern. Two facts motivate this:

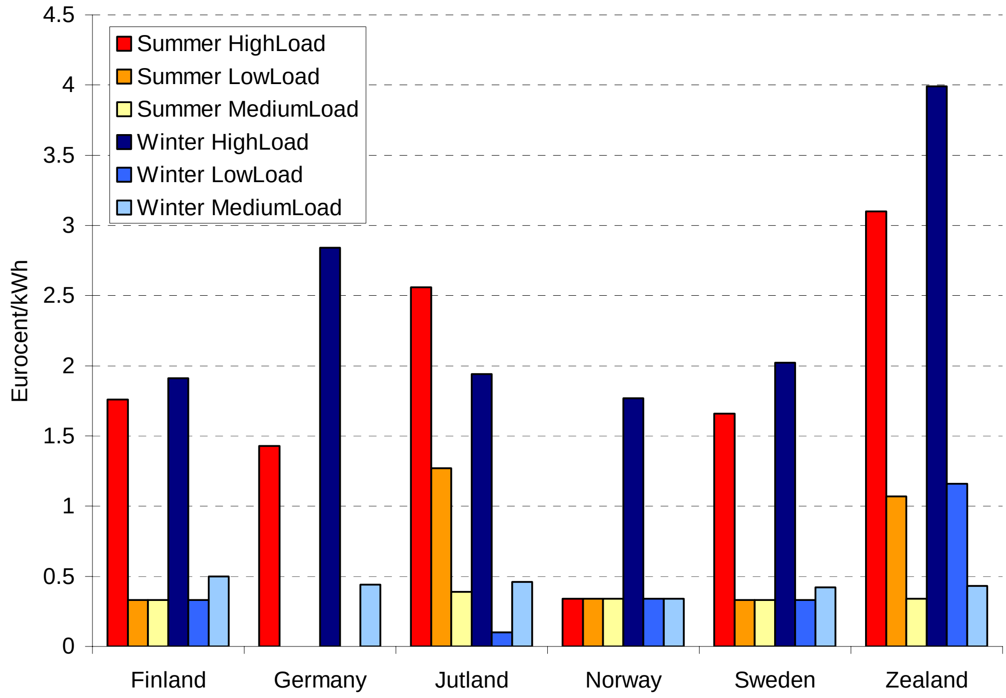
- *The price effect* of reduced hydro power production in one time segment may be larger than the price effect of increased hydro power production in a different time segment. The price can typically increase substantially in winter peak by reduced production whereas the price effect of an increased hydro power production is much smaller in summer low load. This can be explained by two factors. First of all, in high load periods the available free capacity is less implying that it is more difficult for competitors to increase their output as a response to a reduction in output by one party. Secondly (but related), the supply curve is steeper in high load periods implying that a given reduction in output has a large price effect.

- *The generation volumes differ* between the different time segments. Hydro power producers will typically have higher production level in high load than in low load. It can hence be profitable to shift production from high load to low load also with equal price effects (or even if the price effect is larger in low load).

In total, the winter production of hydro power is reduced with 0.8 TWh (total hydro production in a normal year in the Norway, Sweden and Finland is 198 TWh). The difference between the reduction in the winter and the increase during the summer is spill of water. This is hence in accordance with the motivation explained in the two bullet points above.

As expected, this together with other generation reductions, results in different price effect of market power in the different time segments. This is shown in Figure 8. In winter high load the price increase is in all Nordic areas are in the range between 1.8 and 4.0 eurocent/kWh. In summer high load, the price increases are lower since the load in summer high load is smaller than the load in winter high load. The differences between the price increases in the two high load segments are much smaller in Germany than in the Nordic region. This is because the difference in high load is much smaller in Germany than in the Nordic region since there is much less use of electric heating.

Figure 8. Simulated prices in different load segments, difference between perfect competition and market power

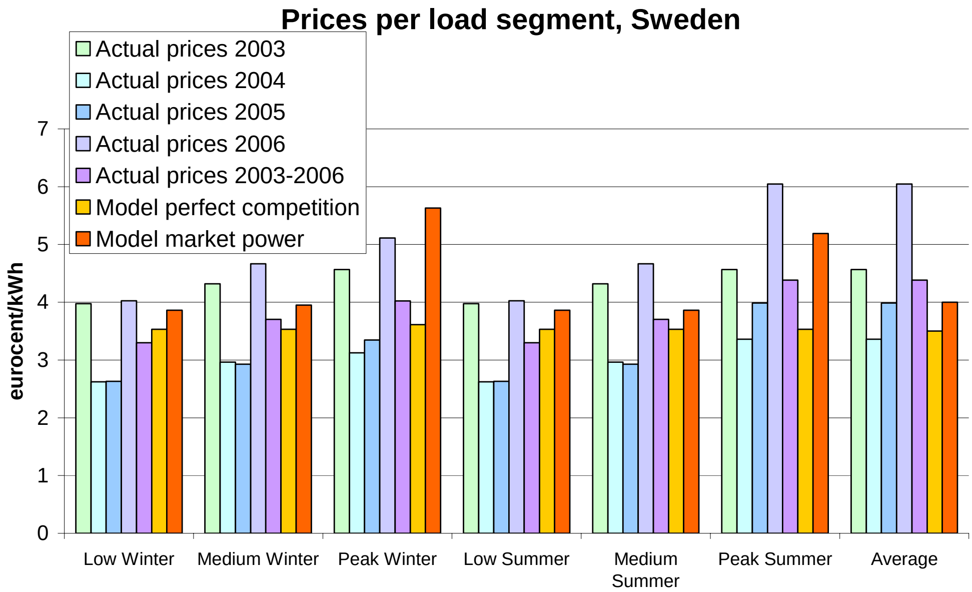


4.2.1 Comparison with actual prices

We have not calibrated the model to match any particular year in detail. The model is set up with data for 2006 in terms of generation capacities, expected demand etc, but we have not made any attempt to calibrate for exact input prices (fuel, emission allowances etc.). However, it might still be valuable to compare the model results with actual prices. From Figure 9 we can see that the actual prices have varied significantly over the last couple of years. There are two extremely important explanations to the observed variations. The first one is variation in precipitation, resulting in large variation in hydro output. Particularly the high prices in 2003 can be explained by this factor. The second factor is the introduction of the European emissions trading from 2005 and the highly volatile emission allowance prices. In addition fuel prices vary over time. In comparison to the variations between years the difference between the modelled prices assuming perfect competition and assuming market power are small, except for the peak load periods. Particularly in the winter peak the simulated market power prices are above any of the observed prices.

Once again, note that the simulations have been made using 2006 data, assuming a normal year. The comparison between model results and the actual prices for 2003-2006 as shown in the figure should thus neither be interpreted as a test of whether market power is being exploited[8] nor as a test of the accuracy of the model.

Figure 9. Prices in Sweden per load block, eurocent/kWh



4.3 The effect of splitting companies

Two simulations have been carried out to simulate the effect of splitting power companies, Vattenfall and Statkraft respectively. More precisely, the two scenarios are defined as:

[8] Damsgaard et.al. (2007) investigates whether market power has been excerised in the Nordic power market in the period 2002-2006.

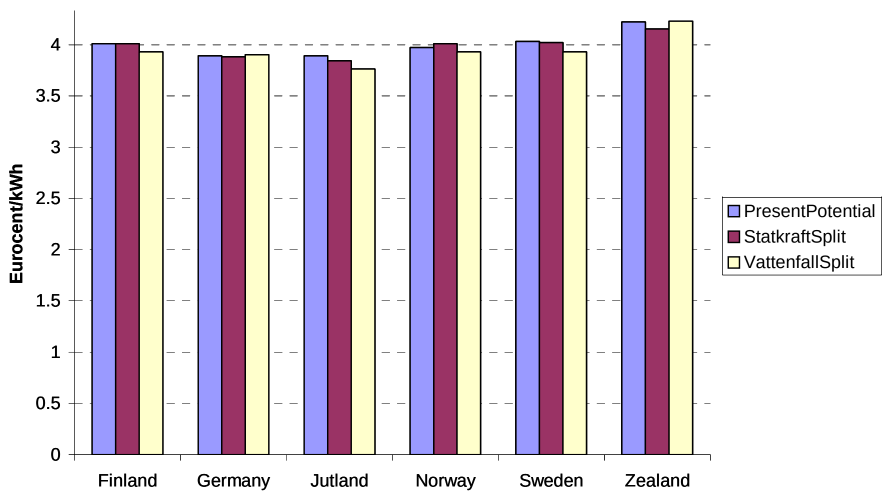
- *Vattenfall divided. In this scenario, Vattenfall has been split into two companies. One of the companies has kept all the hydro power production capacity in Sweden whereas the other company has kept all the other production capacity.*

- *Statkraft divided. In this scenario, Statkraft has been split into two companies, each with 50 % of the hydro power production capacity of the present company. Splitting the production capacity includes inflow, reservoirs and installed capacity; all of them are split 50/50. One of the companies is assumed to keep the minority share of E.ON Sweden.*[9]

The resulting average prices are shown in Figure 10. We can see that splitting one of the two companies does not reduce the potential very much.

Splitting Vattenfall reduces the potential for price increase with 0.1 eurocent/kWh in Sweden, Finland and Jutland, and has hardly any effect in the rest of the area. This decrease corresponds to a decrease in the mark-up with about 1/5 in Sweden, Finland and Zealand (comparing with the mark-ups reported in Table 2).

Figure 10 Average prices with different market structures.



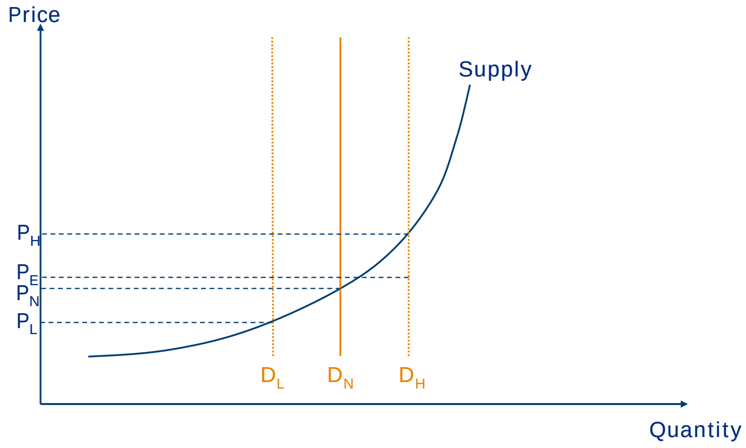
[9] Statkraft's miniority share in E.ON Sweden has since this analysis was made been sold to E.ON.

The effect of splitting Statkraft is fairly similar, but with a smaller effect on prices. We do also get the effect that splitting Statkraft results in a higher average price in Norway. This seems counter-intuitive, but the increase is only marginal.

4.4 Dry and wet years

The model runs presented above are for a so called "normal year" in terms of hydrology and temperature. It is important to note that a normal year is not equivalent to the expected values that would be the result of running simulations for a large number of inflow and temperature scenarios and weighting the results with the probabilities of respective scenarios. This is linked to the general convexity[10] of the supply curve. Consider the simple situation when demand can realize three different levels (high, low and normal) and supply is convex (see Figure 11).[11] In a situation when demand is certain at the "normal" level (D_N) the equilibrium price is P_N. Compare this to a situation when demand can take two alternative values (D_L and D_H) with equal probability. The expected price (P_E) will then be the average of the two prices (P_L and P_H), which due to the convexity of the supply function will be higher than P_N.

Figure 11. Illustration of difference between "normal year price" and expected price



In a perfectly competitive environment will thus the expected price be higher than the price in a normal year, at least if the variations around the normal level is

[10] Strictly speaking the real world supply curve is not convex, but a continous and differentiable approximation of the supply curve would be convex.

equally distributed on both side. This does however not reveal whether the incentives and possibilities to exploit market power will be higher or lower in expectations than in the normal year.

One the one hand will there usually be greater possibilities to exploit market power in shortage situations since the market is operating on a steeper part of the supply curve and there are less excess capacity that can replace any withheld capacity. That would then imply that prices increase even more in a situation with low supply of hydro production.[12]

It is however important to note that the supply is not a smooth, convex function. It is a stepwise linear curve with an overall, convex shape. The potential for market power is however dependent on the local situation around the actual market intersections. The relevant part of the supply curve may hence be concave and then we will expect the opposite effects.

Model simulations

In order to assess the effects of different inflow situations we have, in addition to the normal year, run simulations for a dry and wet year respectively. Dry and wet years are here defined by a 25% probability of having a dryer or wetter year respectively. Figure 12 shows the price increases due to market power in the three different inflow scenarios, for both perfect competition and with simulated market power.

Looking at only the results with perfect competition, we can see that the price drop between normal years and wet years is somewhat larger than the price increase in dry years (compared to normal years), particularly for Norway, Sweden and Finland. This shows that the general convexity of the supply side is

[11] Note that this is equivalent to a situation when the supply curve shift horizontally e.g. due to differences in the available hydro production.
[12] The incentives and possibilities for hydro producers to exploit market power through spilling water might however be lower for two reasons. First of all a producer with a lot of hydro production will have lower production in a dry year, implying that the profits for a given price increase will be reduced. Secondly, the net revenue (i.e. the difference between the market price and the marginal cost) given up by spilling water will increase since the power price is higher in a dry year. This makes spilling water more costly. However, it seems like hydro producers mainly exercise market power by shifting the production in time rather than spilling water.

not dominant in this case. The price fall in Sweden is higher than the price increase in all time segments except for winter peak which is shown in Figure 13. The same figure also shows that the winter peak price is actually higher in wet years than normal years. This may seem counter intuitive, but is due to the demand responding on average prices. Since the prices are lower in low and medium load, the demand in peak load is higher and that may drive up the prices in that particular load block.

From Figure 12 we can see that the difference in average prices between perfect competition and simulated market power is highest in the wet years. From Figure 13, we can see that it is particularly in low and medium load (both summer and winter) that the potential is much higher in wet years than dry and normal years. In wet years, the price in these time segments drop significantly, but market power can pull them back up again. This is done by reducing production in old coal fired power plants. In dry years market power is particularly exercised so to increase the price in winter peak.

Figure 12 Prices with perfect competition and simulated market power in dry, normal and wet years respectively.

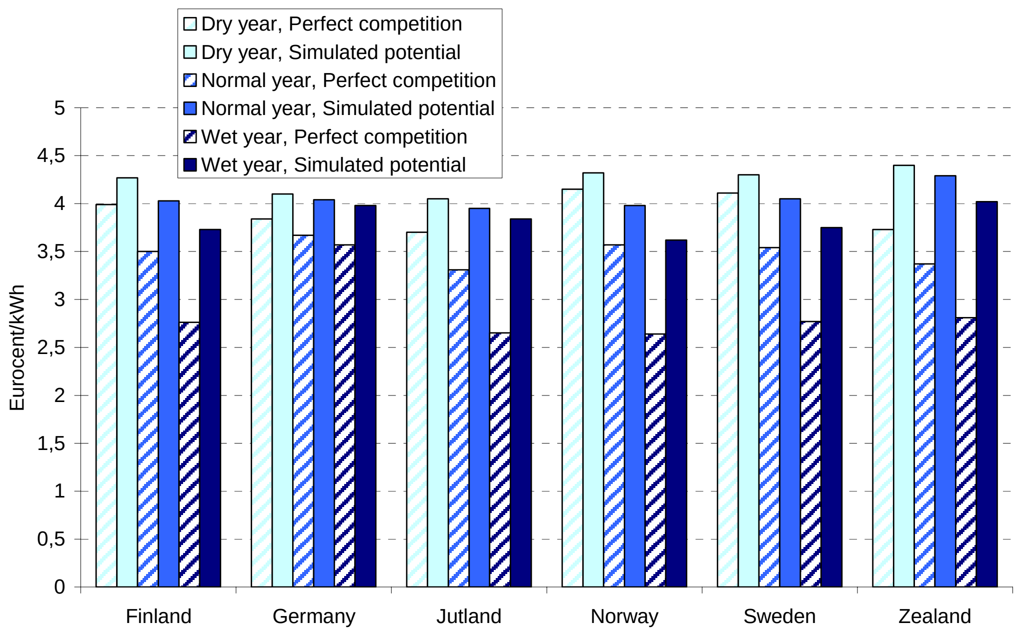
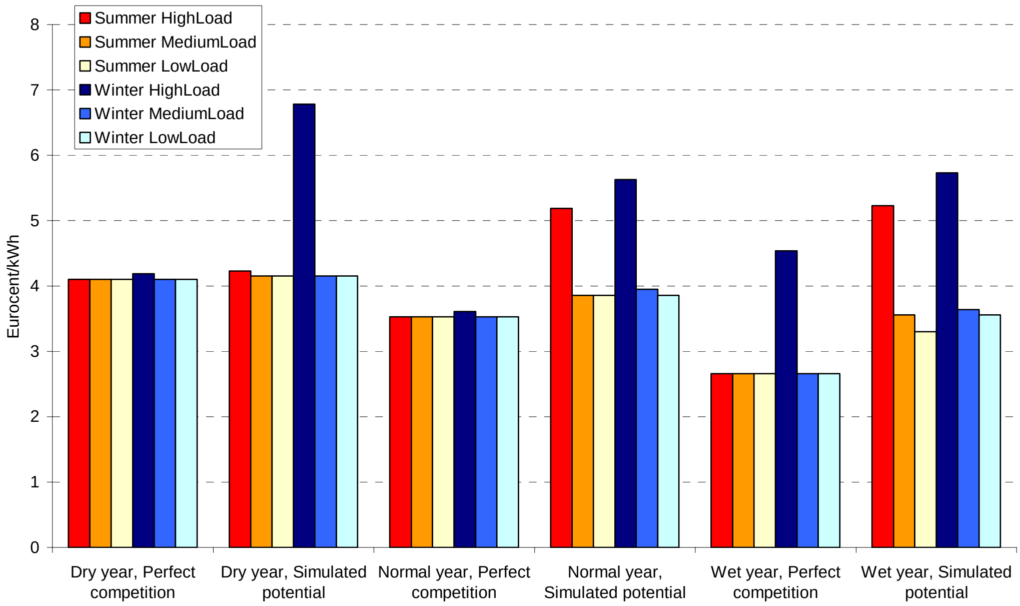


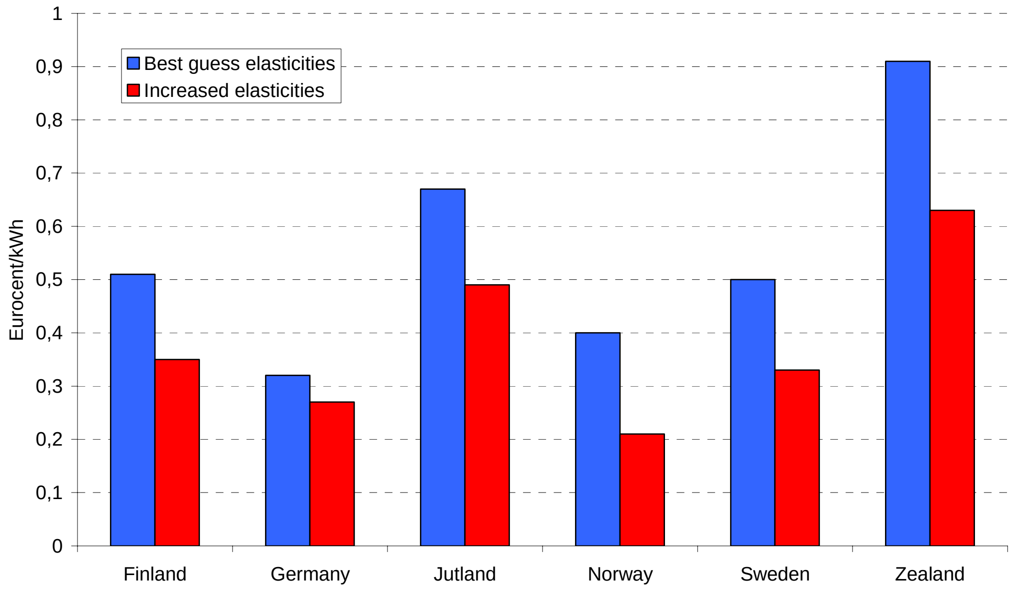
Figure 13 Prices in the different time segments in Sweden.



4.5 Variation in demand elasticity

One reason for electricity markets being vulnerable to market power is the limited inelastic demand. As a sensitivity analysis we have therefore increased all price elasticities with 50 % compared to our main assumptions. As shown by Figure 14 the simulated average mark up is reduced by between 27 % and 47.5 % in the different Nordic market areas (between 0.16 and 0.28 eurocent/kWh). Although an increase of the price elasticities by 50 % is a substantial increase there is also a considerable uncertainty regarding the true price elasticity in electricity markets. This sensitivity analysis thus highlights both the difficulties in accurately assessing the potential for market power, given the uncertainty about the true price elasticity, but also the importance of an elastic demand to mitigate any market power.

Figure 14. Differences in market power with different price elasticities



5 Conclusions

We have analysed the potential for market power in the Nordic power market using a numeric simulation model and applied a supply function equilibrium approach to the strategic behaviour of the large producers. Our results reveal that there is a potential for the large producers to exercise market power. The model simulations suggest that given the current market structure strategic behaviour on the part of the large producers can increase prices by 11 – 27 % in the different market areas compared to the modelled prices assuming perfect competition. The total output in the modelled area (Nordic market and Germany) is reduced by on average only 1.5 %. In Denmark the reduction in output is however about 20 %, while the output is actually somewhat increased in Finland and approximately. In the other market areas the reduction in output is below 2%.

We also study the effect on the potential for market power of reducing the market concentration through splitting some large producers. Two scenarios have been studied. In one scenario the largest producer in Sweden, Vattenfall, is split into two companies, one part getting all the hydro generation capacity and the other part getting all other generation capacity, which result in two companies with approximately the same output but with clearly different technology mix. The effect is that the mark-up on competitive prices is reduced by about 1/5 in Sweden, Finland and Zealand and by less than that in the other market areas. In the other scenario the largest producers in Norway, Statkraft, is split into two equally sized parts. This has a similar effect on the prices as splitting Vattenfall, although generally with a smaller effect on prices.

There are large differences in the availability of hydro production from year to year in the Nordic system and this also has a significant effect on the prices. It is however unclear what effects differences in precipitation have on the potential for market power. Intuitively one would probably expect that the market is more vulnerable to market power in a dry year compared to a normal or wet year. Our model simulations do reveal that this is not necessarily the case. The differences between perfect competition prices and market power prices are largest in wet years. Particularly in low and medium load there is a much larger potential for market power in a wet year compared with dry and normal years. In wet years prices in these segments drop significantly, but market power may pull the prices up again. In dry years market power is primarily exercised in order to increase winter peak prices.

Our model simulations also reveal that the potential for market power is sensitive to the price elasticity of demand. Since the true price elasticity is uncertain this implies difficulties when assessing the potential for market power, but it also highlights the importance of increased demand elasticity in order to mitigate market power.

The electricity in the Nordic power market is produced by a combination of hydro and thermal capacity. To correctly take the dynamic dimension of hydro power optimization into account it is necessary to model the hydro power seen over a longer time horizon, e.g. a year, since the production decision in one period will affect the production decision in any other period. For computational reasons it is necessary to simplify the modelling in other aspects and we have modelled the market with two seasons (summer/winter) and three load blocks in each season. We can thus not fully capture the strategic behaviour hour-by-hour basis.

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Working Paper 2007-003

Exercise of Market Power in the Nordic Power Market

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Exercise of Market Power in the Nordic Power Market[†]

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Abstract

Using a sophisticated model for the Northern European power market we study whether market power has been exercised on the Nordic power market, by comparing actual prices and production patterns with results from model simulations. We study three different time periods from 2001 to 2006 with different characteristics in terms of market fundamentals. Two shortage situations (summer to winter 2002/03 and summer to autumn 2006) and one "normal" situation (summer to autumn 2001). Only for the 2002/03 period, we find strong indications of market power and only for one market area (Jutland). For 2006, the average observed prices are somewhat higher than the simulated prices in all market areas and the results are consistent with market power. It cannot be ruled out that the mark-up between actual prices and simulated prices are driven by differences in expectations rather than market power. For all other time periods and regions, actual prices are slightly below the simulated prices. The overall conclusion is that, with some exceptions, most of the price variations observed over the last years can be explained by market fundamentals, rather than market power.

Key Words

Electricity markets, market power, imperfect competition, oligopoly

JEL Classification

D43, L13

[†] This paper has been written as a part of a research project on market power in the Nordic power market financed by the Swedish Competition Authority, which we gratefully acknowledge. The work has been followed by a reference group consisting of representatives of the Swedish and Norwegian Competition Authorities and we have benefited from their comments. The conclusions and views presented in the paper is the sole responsibility of the authors and do not necessarily reflect the views of the reference group or the financier.

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ECON-Working Paper no. /2007, 21. December 2007, project no. 50830.

1 Introduction

During latter years, the debate on the possible abuse of market power in the Nordic power market has been intensive and raised a lot of media attention. Customers have seen prices increase substantially, and the profits of the large generators have surged. This naturally raises concerns of market power, particularly since power markets in general are sensitive to exploitation of market power and since it has been seen in many other power markets.

At the same time, it is possible to see many other reasons behind the increased prices. In periods the precipitation has been very low – sometimes even extremely low, which means that the marginal production cost increases. Fuel prices have been high, and from 1 January 2005, a new system for trade in emission allowances for carbon dioxide was introduced in Europe. Although hydro and nuclear power largely covers the Nordic market, coal-fired power plants often provide the marginal generation. Marginal cost pricing can thus lead to a significant price increase, although it is only a limited part of the generation that is affected by a cost increase. This is however not market power.

The aim of this work is to find indications for market power in the Nordic power market. We will test whether prices observed in the market corresponds with theoretical prices in a market with perfect competition. To test market power we use a power market model for the North European market with hourly resolution. Prices (i.e. modelled system marginal costs) in certain periods will be compared with observed spot prices at Nord Pool. These price-cost mark-ups can be interpreted as indications of market power. Deviations in a few time periods may be attributed to other causes, but lasting and large price-cost mark-ups would be a strong indication of market power.

2 Literature

Following deregulations (and in some cases privatization) of wholesale power markets problems of market power have been seen in many national or regional markets. The English/Wales market was deregulated from 1990. An early analysis of the potential for market power in that market was made by green and Newbery (1992). They modelled the market using the concept of supply function equilibrium[1] and found a considerable potential for market power. One apparent explanation is that the English market at that time in practice consisted of two companies that could meet the marginal demand.[2] An alternative type of modelling is made by von der Ferh and Harbord (1993), who models the market the English pool as a first-price, sealed-bid, multiunit auction.

Wolfram has analysed the English market in two papers (Wolfram 1998, 1999) and claims that supply function equilibrium models do not capture the spot market particularly well and that the prices have been lower than what these models predict. Wolfram (1998) assumes that on a competitive market no company can take any actions to affect the market price. This is the basis for an estimation method where bidding and supply decision for each individual company is analysed with the purpose of detecting successful attempts to affect the prices. Wolak and Patrick (1997) have also used a similar approach in their analysis of the English market.

An alternative approach is to look at the market level, instead of the company level. With this approach implies an analysis of whether the market as a whole sets competitive prices (equal to marginal costs), given the generation capacity of all the market participants. This approach was used by e.g. Wolfram (1999), who analysed the price-cost mark-up calculated based on the companies' marginal cost for each half hour period during 18 month. Her conclusion was that the prices are significantly higher than observed marginal costs, but that the producers have not fully exploited the inelastic demand. Prices are therefore lower than what usual oligopoly models predict.

Following the failed deregulation in California and the high prices, levels that were reached a number of analyses have been made for the Californian market. Borenstein, Bushnell and Wolak (2002), uses as an empirical approach similar to

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[1] The concept of supply function equilibrium was initially developed by Klemperer and Meyer (1989)

[2] Nuclear power was as in a separate company, but it only provided base load and did not affect the market price on the margin.

Wolfram (1999), and split the electricity prices in generation costs, inframarginal competitive rents and market power. Their conclusion is that the price increase between the summer 1999 and the summer 2000 was to almost 60 per cent caused by market power.

Cho and Kim (2007) develops the approach used by Borenstein, Bushnell and Wolak (2002) further, but in addition the possibilities for transferring electricity over the grid is explicitly included. The transmission capacity of the grids is limited, which in most electricity markets give rise to bottlenecks from time to time. This implies that even though there is “excess supply” in one area and a “deficit” in an other area the prices will not be equalized. More expensive generation capacity will thus have to be used in the deficit area, at the same time, as cheaper capacity is idle in the surplus area. If this is not taken into consideration, the effects of market power may be overestimated. Cho and Kim (2007) also find that the prices were substantially affected by market power, but compared with Borenstein, Bushnell and Wolak (2002) the quantitative effect is much lower. Cho and Kim (2007) find that the finite transmission capacity accounts for 29-38% of the total annual welfare loss, while the remaining can be explained by market power.

The estimate for market power found by Borenstein, Bushnell and Wolak (2002) usually exceeds the estimates found by more than 20 per cent, and in some cases by more than 30 per cent, indicating the importance of the limitations in transmission capacity.

The dramatic development in California has spurred a number of analyses. Two other examples are Puller (2001), who uses the same approach as Wolfram (1998) and Joskow and Kahn (2002) who uses both the above-mentioned approaches.

The potential for market power on the Nordic electricity market has been analysed in a number of studies. In an ex-ante analysis, Andersson and Bergman (1995) modelled the market as a Cournot market, and found significant scope for market power. The integration of the Swedish and Norwegian market was however one important way to reduce the market power. Amundsen and Bergman (2002) used a similar model but also included the effect of cross-ownership, which was showed to restore market power to a significant degree. Halseth (1998) used a version of supply function equilibrium to simulate the market equilibrium using ECON's model for the Nordic power market. One result in that study it primarily was Vattenfall's position that caused a problem of market power primarily, through a possibility to reduce the nuclear output.

There are also a few empirical studies of the use of market power on the Nordic power market. Johnsen, Verma and Wolfram (1999) analysed the prices in five price areas in the Norwegian market, with the hypothesis that the producers have the largest possibilities to exploit market power when the transmission constraints are binding. They find some empirical support that the prices in the local markets are higher during periods of transmission congestions.

Hjalmarsson (2000) take as a starting point that a profit maximizing company sets marginal cost equal to marginal revenue. In perfect competition the marginal revenue equals the market price, while with market power the marginal revenue will be less than the market price. Hjalmarsson uses this when estimating supply- and demand relationships to test for market power with an assumption of no transmission congestions. The conclusion is that no market power can be found on the Nord Pool market. Hjalmarsson uses data from week 2 1996 to week 16 1999. The major part of this period was however characterised by ample supply of water in the hydro reservoirs, and the pre-deregulation market had excess capacity. This means that one would expect that the market power during this period was limited.

Since then we have seen both much higher prices, periods of lower (and even very low) precipitation levels, decreasing supply/demand ratios and an increased market concentration; all factors that is likely to lead to increasing problems with market power.

In this paper, we will use an approach similar to the one used by Cho and Kim (2007), but applied to the Nordic electricity market. This means that we will study the market outcome rather than the behaviour of individual firms and the focus of the analysis is on the price-cost mark-up.

3 The method

Spot prices observed at the Nordic power exchange Nord Pool is set hour by hour based on supply and demand bids from producers and consumers in the Nordic power market. In a competitive market these prices will equal marginal cost, and the price-cost mark-up is a measurement of market power in the market.

The previous analyses that have been made for the English and Californian markets were naturally because both these markets are primarily based on thermal electricity generation. For thermal production, it is relatively simple to calculate the marginal cost based since the technologies and fuel costs are well known. Furthermore, with some exceptions, the production decisions in one period are essentially independent of production decisions in any other period.[3]

The Nordic power system is on the contrary to a considerable extent hydro power dominated. Somewhat simplified the north-western part of the system (Norway and northern Sweden) are hydro dominated, while the southern (southern Sweden and Denmark) and eastern (Finland) part of the system is thermal dominated. Wolfram (1999) does not deal with hydro power at all, while both Borenstein, Bushnell and Wolak (2002) and Cho and Kim (2007) have assumed that the existing hydro power has not been used strategically. This may be a realistic assumption for the Californian market, but would be a very strong assumption for the Nordic market.

The existence of hydro power causes two interrelated complications. Hydro power with storage capacity implies that the production decisions are intertemporal; production in one period generally implies less production in an other time period. This introduces a dynamic component in the decisions. This dynamic implies that it is not the variable production cost that is the relevant marginal cost that should be used for measuring the price-cost mark-up. Instead, it is the opportunity cost of the water (water value) that is the production parameter. Calculating the water value is a complex dynamic optimization problem, but it is necessary when trying to measure market power on the Nordic power market. Simply speaking the water value is the marginal cost of the power production that cannot be met by hydro power or exogenous power production. In reality, the water value will also be different for each individual reservoir, depending on size of reservoir compared with turbine capacity.

If companies are price takers and there are no restrictions on the storage capacity the production would first be allocated to the periods with the highest demand, and then successively to periods with lower and lower demand. This would lead to complete price equalization over time. In practice, there exist several restrictions, e.g., storage capacity, effect capacity and transmission capacity that make such complete price equalization impossible. Efficient production, both from a price taking producer and for society, does however implies that the hydro power generation to the extent it is possible will be allocated to the periods with the highest demand (price). This implies that the water value will primarily be determined by the marginal cost for the alternative thermal production (and in periods determined by effect capacity restrictions). This implies that also on a market with perfect competition will the prices in certain periods exceed the marginal generation cost during in that particular period, since the water is saved for production in more expensive hours.

A hydro producer can exploit market power in two ways. First, it can restrict the total output, which however requires “spilling water”, i.e., not use the water for generation. This is probably easy to detect if it is done on a systematic and larger scale. The second possibility is to shift generation over time. Instead of trying to equalize the prices over time, a hydro producer with market power shift production from the high demand periods to lower demand periods. During high demand periods, the market operates on a “steep” part of the supply curve and a reduction in output will have a large effect on the price. In low demand periods, the supply curve is flatter and a change in output has only a small effect on the market price.

When analysing market power in the Nordic market one need to take into consideration three types of generation. Hydro power and thermal generation has

[3] An important exception from this is that thermal generators have start and stop costs, which makes decisions

already been discussed above. Not all thermal generation however has the same characteristics. Some of the thermal power generation is can be seen as exogenous, since it is determined by the heat demand from combined heat and power plants. This type of production does not react to the market price for electricity. The same is also true for run-of-river hydro (without storage capacity) and wind power. Condensing and extraction[4] power plants do however react to the prices.

For the analysis in this paper, we have used a model for the Northern European power market, ECON BID. The basic approach is to compare the actual power prices with the modelled prices. A power market model will never have the accuracy so that every difference between the model result and observed data can be interpreted as market power or other market imperfections. Firstly, it is not possible to enter all relevant information in a model. Secondly, there will always be different knowledge and expectations between different participants in the market. Observed price differences will therefore be indications, not evidence for market power. Systematic deviations from marginal cost can however be seen as a strong indication of market power, and this particularly if these deviations are "large".

3.1 The model

ECON BID is a model for the Northern European power market that has been developed over the last three years.[5]. The model was developed to capture the complex interplay between thermal, wind, and hydro in Northern Europe and as a result, the model produces price levels, trade, and demand at an hourly resolution. Hence, the model cannot only be used to make price forecasts, but can be used to study the profitability of inter-connectors, the effects of more wind power, the economic effects of increased trade possibilities, or the economics of a single

somewhat intertemporal. Furthermore, nuclear power plants generally have little short-run flexibility.

[4] Plants with heat delivery obligations, but more power can be delivered if it is profitable

[5] ECON BID is a proprietory model owned by Econ Pöyry. The development of BID was supported by the Norwegian TSO Statnett, the Danish TSO Eneginet.dk, the Dutch TSO Tennet, as well as the Norwegian Ministry for Petroleum and Energy. BID stands for "Better Investment Decisions". The motivation behind BID was that, in order to study the effects and profitability of investments in the power market, one needs an hour-by-hour power market model that allows simulating the complex interplay between thermal (including CHP), hydro, and wind technologies.

power plant. The model also allows welfare analysis of, for example, an inter-connector, capturing the effects on congestion rent, consumer surplus, or producer surplus. For this paper, the model has been adapted to study the possible abuse of market power. The most important adaptation is to allow for continuous new input over time, as new information arrive. This is not necessary for the other objectives above, but if one is to compare actual and modelled prices new information need to be included in the model in approximately the same way as it enters the market.

3.1.1 The methodology of ECON BID

The BID model is a fundamental model that estimates the price by calculating the intersections between supply and demand. The model has a regional structure with specified transmission capacity and trading regime between the regions. For each region, there are specified demand curves with some price elasticity for a number of consumer groups. The supply curve is constructed as a merit order curve defined by production capacities and short run marginal costs. The model includes a “water value” module for calculations of the short run supply from *regulated* hydro power plants. In the market simulation module each generator bid in their desired generation according to their marginal costs, where hydro producers base their bids on their water value which is fed in from the “water value” module. The market simulation algorithm has 168 chronological hours per week. The chronology allows for inclusion of start-stop costs in thermal plants, and the fine time resolution enables better inclusion of the stochasticity of wind power and non-perfect trade patterns.

3.1.2 Geographical Scope

The standard version of BID covers the Nordic region (except Iceland), the Netherlands, Belgium, France, Germany, Poland, Switzerland and Austria.[6] Some of these countries are divided into several zones: Norway into 7 regions, Sweden into 4 regions and Denmark into 2 regions. All data is specified on this regional level, including hydrology data, demand, generation set, distribution network and cross-border transmission network data.

[6] The model can easily be extended to include more countries.

3.1.3 Time Structure

The simulations are run on a two-level time resolution. First, the year is divided into weeks, and each week is divided into chronological hours. The model then optimizes the system for each week of the year, taking hourly constraints and system costs, such as start-stop costs, into account. This is further described below.

3.1.4 Demand

In its normal set-up, the model includes a detailed modelling of demand. In contrast to many other models demand is price elastic and not fixed exogenously.[7] Since temperature variations are important for driving demand (for electric heating), we have in this application simplified the demand side and used observed hour-by-hour demand. The focus is here on the use of market power and it is then important to estimate the marginal cost of the system for the actual demand levels. This simplifies the analysis and makes it easier to detect market power, but it also implies that we are not able to estimate the deadweight loss of any use of market power. In the case that simulated prices deviate considerably from the observed prices changes in demand due to the price differences would also be important. If market power is being exercised the observed demand will be lower than the demand under perfect competition, and the marginal cost in the model will then be under estimated. Correspondingly, the marginal cost will be over estimated in periods when the price is being reduced due to shifting of water (over production in low load periods).

3.1.5 Transmission Structure

Cross border transmission is modelled from an economic standpoint (rather than via a physical load-flow approach), with each connection from any one region to any other region having a specified (linear) loss, cost, availability, and capacity.

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[7] The demand is usually calculated within the model based on assumed price elasticities and a calibration point. The demand is specified as a Cobb-Douglas function. The model distinguishes between hourly price elasticity, i.e., the ability of demand to react to short-term, hourly price fluctuations, and weekly elasticities, i.e., the ability to adjust weekly demand as a reaction to prices. In addition, the model allows specification of up to five demand groups, each with its own demand curve. At the moment, those five groups are households, power intensive industry, service industry, other industry and electric boilers. The latter category is of importance in the Nordic context.

In general, there are three types of inter regional transmission:

- Normally the transmission is price-based, i.e. transmission between regions is based on price differences (the price includes losses and transmission fees).

- In some cases, the transmission capacity is fixed between regions based on contracts between the regions (for example Finland and Russia).

- Transmission can be a combination of the price-based and fixed. In this case, the model allocates the line capacity required for the fixed trade flows to the fixed trade, and only the remainder of the capacity is available for price-based trade.

Within a given region, we are assuming that there are no transmission bottlenecks. Internal transmission and distribution losses, however, are accounted for by using linear loss functions, with user specified parameters.

3.1.6 Supply

Thermal power

Thermal technologies are characterized by technology type (condensing, extraction, CHP), fuel types, efficiencies, start-stop costs, part load efficiencies, operating costs, and availabilities. When it comes to availability of other power production than nuclear, we use average availability profiles.

Combined heat and power (CHP)

The model allows detailed combined heat and power (CHP) modelling. The model distinguishes between extraction CHP and backpressure CHP. Within the latter category, a further distinction between public and industrial CHP is applied. For each CHP technology, production profiles can be specified.

Wind power

The wind power production is simulated stochastically at an hourly resolution. Based on observed historical wind data, the simulation process ensures that difference between consecutive hours and between different market areas are realistic. This is very important in order to get realistic start-stop costs and price differences between areas at an hourly basis.

Hydro power

While e.g. thermal power plants have relatively clearly defined marginal cost curves which can be used as a basis for bidding, the same is not valid for hydro power. A hydro power producer placing a bid instead has to take the opportunity cost of saving the water and producing at a different point of time. It is normally not the marginal cost of the hydro plant that is important for the bidding behaviour. Modelling of hydro power thus become more complex.

The inflows to the various hydro power regions are simulated stochastically using historically observed inflows. The modelling of hydro power simulates the way hydro is priced and operated in the market. Hydro is split into Reservoir (or storage) hydro and Run-Of-River hydro, i.e. hydro plant with very small or no effective storage.

Inflows are modelled on multiple levels, with inflow expectation, the ability of generators to forecast inflows ahead of time, and actual inflow levels (and the consequent impact of errors in expectation, forecast ability and (systematic) errors in forecasting), all specified explicitly in the model. In the simulations made for this paper we have updated the input data, including inflow, for each for week period. That essentially means that the market players have perfect foresight regarding hydro inflow over the next four weeks, but for any period beyond this they expect “normal” conditions.

The hydro reservoir structure in each hydro-enabled region is modelled as a single, large hydro reservoir that is effectively the sum of all the hydro reservoirs in the region. This simplification implies it is not possible to calculate the water value for an individual plant. Variations in water values between plants in a given region are taken into account by assuming a distribution of the water value around the water value calculated for the region. Each reservoir is modelled as a store of power (rather than directly as water). Thus, all storage (and consequently inflow) data is measured in units of power (e.g. storage in TWh, inflow in GWh per period).

Release from each reservoir is in the form of spill and generation. Spill occurs when the reservoir storage levels exceed the maximum, or else generation levels in a given period are less than the minimum release level required for that period, and the shortfall is met by spilled release. Total release in a period is also subject to a specified maximum release level.

A stochastic dynamic programming methodology is used to construct water values for the complete range of storage levels for each period in the analysis. Two concepts are used to undertake this analysis: the *Demand Curve for Release (DCR)* and the *Demand Curve for Storage (DCS).* Given the market conditions at a given time the model constructs a DCR, i.e., what the market is willing to buy given different water values and a DCS, i.e. the water value curve.

Demand Curve for Release

The DCR is computed via the use of the single-period market-clearing model from the Simulation Module in the model. Using the market clearing model, for a given set of market conditions in a given time period, and a fixed marginal water value for the reservoir, we are able to calculate corresponding generation levels for each plant in the market, including the hydro plant. The DCR for a given time period is calculated for all regions (or zones) and load blocks. A pre-defined range of discrete water values is used for the reservoir in the current region and for the combined reservoir for all the other regions. For each combination of these water values, the single-period model then computes the corresponding release levels (for the current and combined region). It is important to remember here that each period is treated independently, meaning that the releases of one given period does not affect the releases of the next.

From the release output, a generation pair for region *CC* and the combined region is given for time period *t*:

One reservoir case:

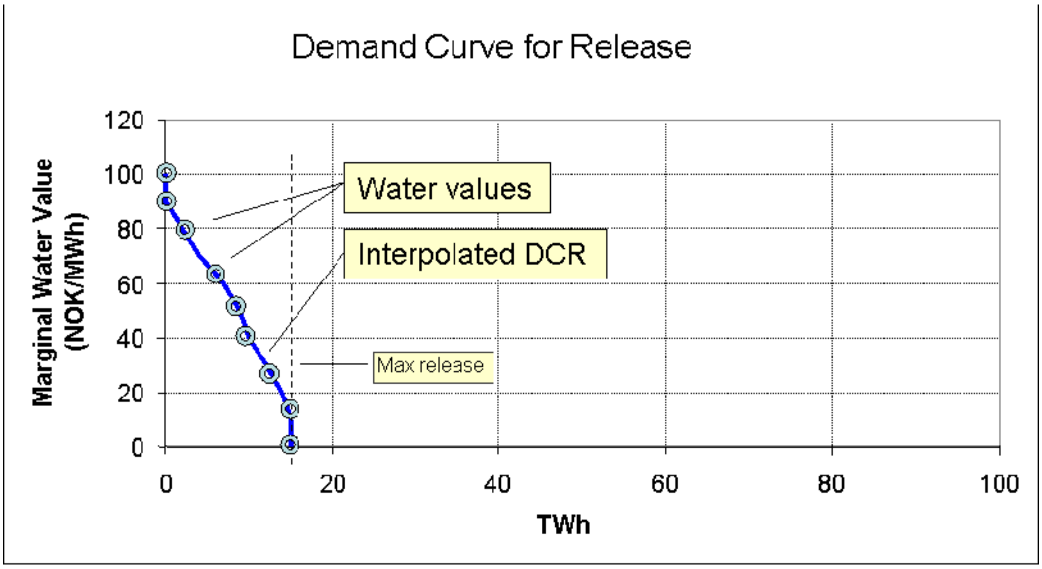
$DCR_t(WV_{CC})$ = Release = R_{CC}

Multi-reservoir case:

$DCR_t(WV_{CC},WV_{OT})$ = Release = (R_{CC},R_{OT})

An example of a two dimensional DCR-curve (only one reservoir) is shown in Figure 1 (note that, by convention, water values are shown on the y-axis, and generation (release) on the x-axis). The water value can be considered analogous to the marginal generation cost for a thermal plant. Thus, clearly, the lower the water values the greater the generation from the plant. Before interpolation, the DCR-curve will often have a staircase – shape, with only a few levels of hydro generation demand for a number of water value levels (either you produce a lot or nothing).

Figure 1. Two dimensional DCR (period t), example



Source: ECON

Demand Curve for Storage

While the DCR gives the desired level of release in a period for a given water value, the DCS gives the desired level of storage for a given water value (or conversely the marginal value of water given a certain level of storage) in the period. The DCS is thus known as the Water Value Curve. Seeing it as a demand curve for storage enables the calculation methodology to be expressed as the addition and subtraction of demand curves for water.

In any given period, water can only be released or stored for the next period (deliberate spilling of water is not considered an option in the modelling). Calculation of the DCSs for each period then involves the iterative addition and subtraction of the various demand curves for storage and release. The demand for water at the end of a period is given by the demand for water at the start of the period, less the demand for water to be released, adjusted for the expected level of inflow in the period.

First, let the DCS for the start of a given period *t*, be denoted $DCS_{(t)}$. The DCS for this period is based on three parameters; the DCS for the start of the previous period, $DCS_{(t-1)}$, the release in the previous period, $DCR_{(t-1)}$, and the inflow in the previous period, $f_{(t-1)}$.

$$DCS_{(t)} = DCS_{(t-1)} - DCR_{(t-1)} + f_{(t-1)}$$

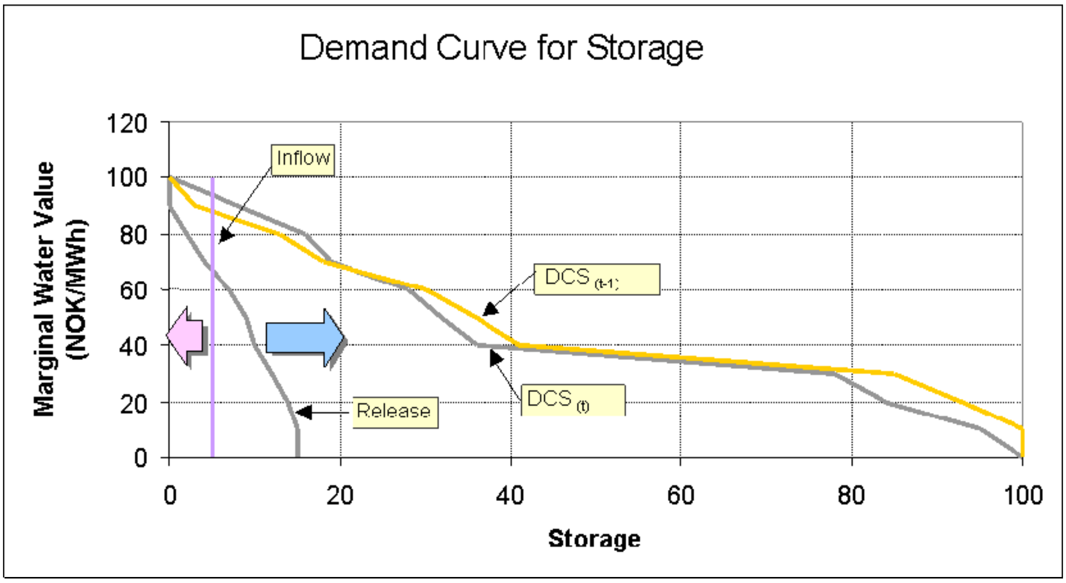
Implicitly, we here assume that water can only be stored or released.

The DCS is calculated backwards in the model. We then solve the equation above for $DCS_{(t-1)}$. This gives us the following:

$$DCS_{(t-1)} = DCS_{(t)} + DCR_{(t-1)} - f_{(t-1)}$$

The process of calculating $DCS_{(t-1)}$ is illustrated graphically in Figure 2. The $DCR_{(t-1)}$ curve is added to the $DCS_{(t)}$. The result is then adjusted by the inflow for period *t-1* to obtain the $DCS_{(t-1)}$ curve in Figure 2.

Figure 2 *Calculating two-dimensional $DCS_{(t)}$ in period t based on the knowledge of $DCS_{(t-1)}$, $release_{(t)}$ and $Inflow_{(t)}$*



Source: ECON

The optimal decisions will often aim at trying to equalize the DCS for both periods. If you release more, the value of release decreases, and the value of storage increases. In equilibrium these two values will approach each other.

Note that the stochastic nature of the inflow conditions is captured by replacing *f* in the exposition above with a random variable *F*, representing the potential distribution of hydro inflows[8]. This random variable has the same distribution as the historical inflows.[9] For a discrete number of inflows and their corresponding probabilities, the expected marginal value of water for a given storage level is then simply the weighted average of the marginal water values from the corresponding DCS curves at that storage level.

More precisely, the calculation of the final DCS – curve is performed in three steps.

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8 That is, we have a number of inflows *f*, each with a given probability. Each creates a DCS; the expected DCS is the probability-weighted sum of these DCSs.

9 Alternatively it can be biased towards dry or wet years to capture, say, a generator's risk adjusted behaviour (e.g. a generator making a conservative assumption of hydro inflow levels in determining operating targets and decisions).

Step 1: For given water value WV_{CC} in reservoir *CC* (one reservoir case) or for a water value pair (WV_{CC}, WV_{OT}) (two reservoir case), the demand for hydro generation (DCR) is first taken into account:

One reservoir case:

$$DCS_t\left(WV_{CC}\right) = DCS_{t-1}\left(WV_{CC}\right) - DCR_{t-1}\left(WV_{CC}\right)$$

Two reservoir case:

$$DCS_t\left(WV_{CC}, WV_{OT}\right) = DCS_{t-1}\left(WV_{CC}, WV_{OT}\right) - DCR_{t-1}\left(WV_{CC}, WV_{OT}\right)$$

or

$$DCS_{t-1}\left(WV_{CC}\right) = DCS_t\left(WV_{CC}\right) + DCR_{t-1}\left(WV_{CC}\right)$$

$$DCS_{t-1}\left(WV_{CC}, WV_{OT}\right) = DCS_t\left(WV_{CC}, WV_{OT}\right) + DCR_{t-1}\left(WV_{CC}, WV_{OT}\right)$$

Consequently, the DCS is pushed outwards for all discrete water values. WV_{OT} gives the water value for the combined reservoir.

Step 2: The preliminary DCS curve is then inverted to give:

One reservoir case:

$$\hat{DCS}_{t-1}\left(R_{CC}\right) = \left[DCS_{t-1}\left(WV_{CC}\right)\right]^{-1}$$

Two reservoir case:

$$\hat{DCS}_{t-1}\left(R_{CC}, R_{OT}\right) = \left[DCS_{t-1}\left(WV_{CC}, WV_{OT}\right)\right]^{-1}$$

The inverted $\hat{DCS}$ therefore has water values as output and storage levels as arguments.

Step 3: The expected, or probability weighted DCS is then calculated by adding the impact of the inflow of period *t*:

One reservoir case:

$$DCS_{t-1}(R_{CC}) = \sum_{m=1}^{M}\left[\hat{DCS}_{t-1}\left(R_{CC} + f_{t-1}^{m}\right) \cdot p_{t-1}^{m} \right]$$

Two reservoir case:

$$DCS_{t-1}(R_{CC}, R_{OT}) = \sum_{m=1}^{M}\left[\hat{DCS}_{t-1}\left(R_{CC} + f_{t-1}^{m}, R_{OT} + \left[F_{t-1}^{m} - f_{t-1}^{m}\right]\right) \cdot p_{t-1}^{m} \right]$$

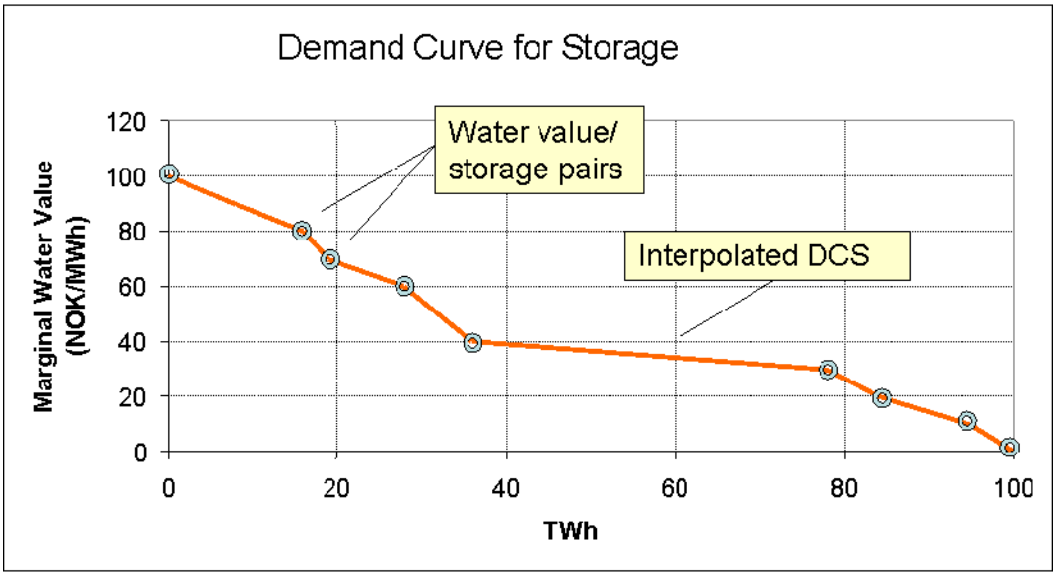
In these equations p_{t-1}^{m} is the probability of one particular inflow series *m* in period *t-1*. R_{CC} represents a discrete storage value in reservoir *CC*, while R_{OT} gives the combined storage level for all other magazines. The inversion does not have to be performed for each possible inflow series. This is because demand for hydro generation (DCR) and inflow f_{t-1}^{m} is subtracted and added in the same amount for all possible discrete water values. For a certain storage level pair (R_{CC}, R_{OT}) the water value will equal the water value found using $\hat{DCS}$ for a storage level of $\left(R_{CC} + f_{t-1}^{m}, R_{OT} + \left[F_{t-1}^{m} - f_{t-1}^{m}\right]\right)$. F_{t-1}^{m} gives in this case the aggregated inflow level in period *t-1* for all zones except zone *CC* for inflow scenario *m*.

Thus, we now have an iterative methodology for calculating the DCS for each period. First, an end-of-horizon period, period *T*, is chosen to be a "sufficient" number of periods in the future. For example, if we wish to simulate a single year, the end-of-horizon may be a further 5 years ahead. Assume also that we have an end-of horizon DCS. As by recursively adding the DCR for period *T* to the end-of-horizon DCS and adjusting for inflow, we obtain the beginning of period DCS for period *T-1*. The process is then repeated for period *T-2*, then *T-3*, and so on to period 1. As long as period *T* is far enough into the future, and errors involved in specifying ("guessing") the DCS for that period will have been eliminated by the time the DCS curves are being calculated for the single year (from period *1*) that we are interested in.

DCS over the model period

As mentioned, the above procedure is in practice conducted for a set of discrete water values, giving a set of discrete water value/storage pairs. Interpolating between these pairs gives the full DCS. This curve is illustrated in the Figure 3.

Figure 3 Single period DCS for one reservoir (period (t))

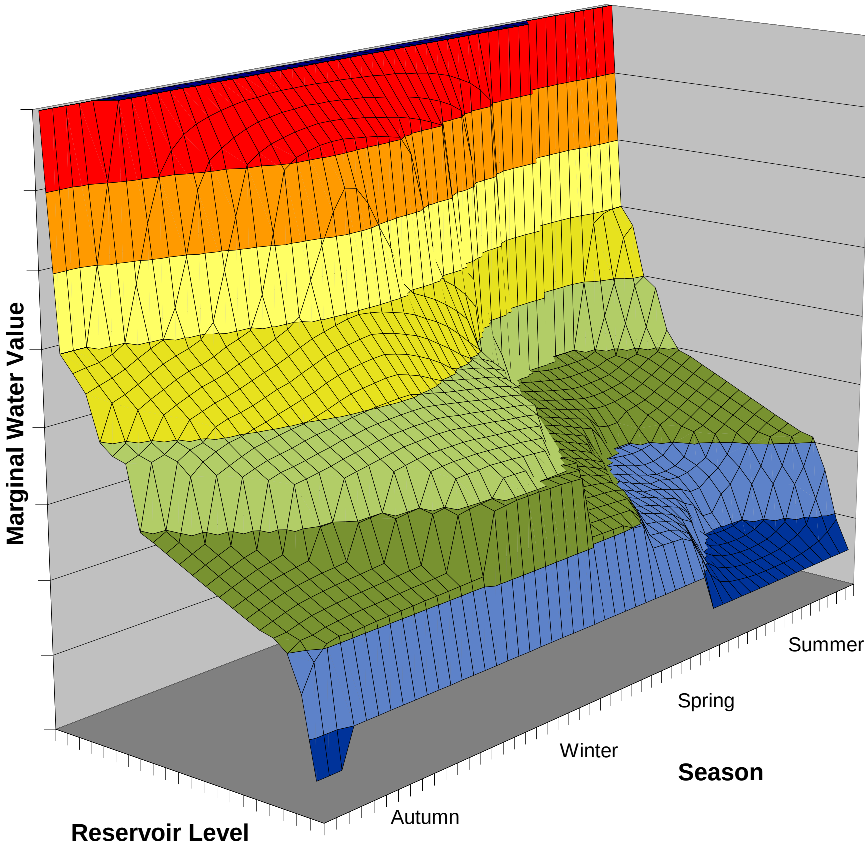


Source: ECON

Calculating the end-of-period DCS for each period in the analysis from "end to start" gives marginal water value "surface" over the time horizon of the analysis. Thus, given a period and storage level in the reservoir, the corresponding marginal water value can be read from the graph and used to make a release (generation) decision in that period.

Figure 4 illustrates 52 different DCS curves over a complete year for an example reservoir. Note the development of the water values for given storage levels over the different weeks and seasons, reflecting such factors as demand levels, thermal plant availability, and inflow levels.

Figure 4 Example of the 52 different DCS for a single year



Source: ECON

Snow reservoirs

We have not modeled the snow reservoirs, i.e. the water contained in the snow that will eventually end up in the reservoirs. The effect of this is that deviations in the snow reservoir will result in a chock during snow smelting. In reality, the market players have some information about the snow reservoirs. The periods modeled here are however not significantly effected by this. The model is currently being furthered developed to e.g. take the snow reservoirs into account.

3.1.7 Simulation module (market clearing)

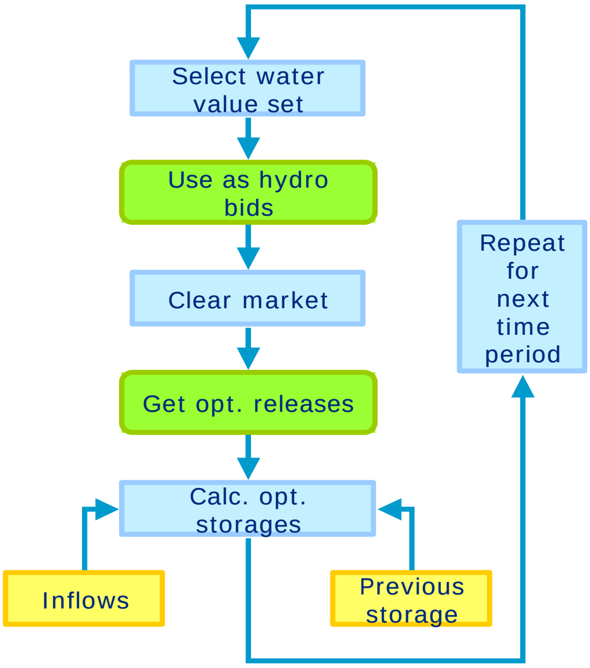
In the simulation module, prices are found where demand equals supply for each zone adjusted for trade between the zones. The hydro power bid their production according their water values as described in the section below.

The simulation module calculates the optimal solution for one week at a time. This allows the modeling of start/stop costs and ramping restrictions on plant operation over a weekly period. In the model, costs of starting up new units is assessed by introducing a variable for each technology that specifies how much of the installed capacity that is currently online. A start-up cost is added when this capacity is increased (from one time step to the next). Furthermore, units operating in part load are penalized due to the lower efficiency of operating in this point. Hence, if less power is needed, e.g. during night, capacity will be taken offline if the increased costs of running the units in part-load is bigger than the costs of starting up the unit later on, when more capacity is needed again. However, to know which cost is higher, the model must see some time ahead. Therefore, the whole week is optimised at the same time.

Hydro power in the simulation module

The simulation is started by deciding a starting storage on the reservoirs. For this paper, we have used the actual reservoir levels at the start of the first simulation and the re-started the simulation considering actual inflow. The model finds the water value for this storage level from the DCS, and the corresponding level of preferred release from the DCR. This is bid into the market and the market is cleared. The release takes place, and based on the previous storage, the release and inflow, the new storage is calculated. This is repeated each period of analysis. Figure 5 shows this loop.

Figure 5 Simulation module structure



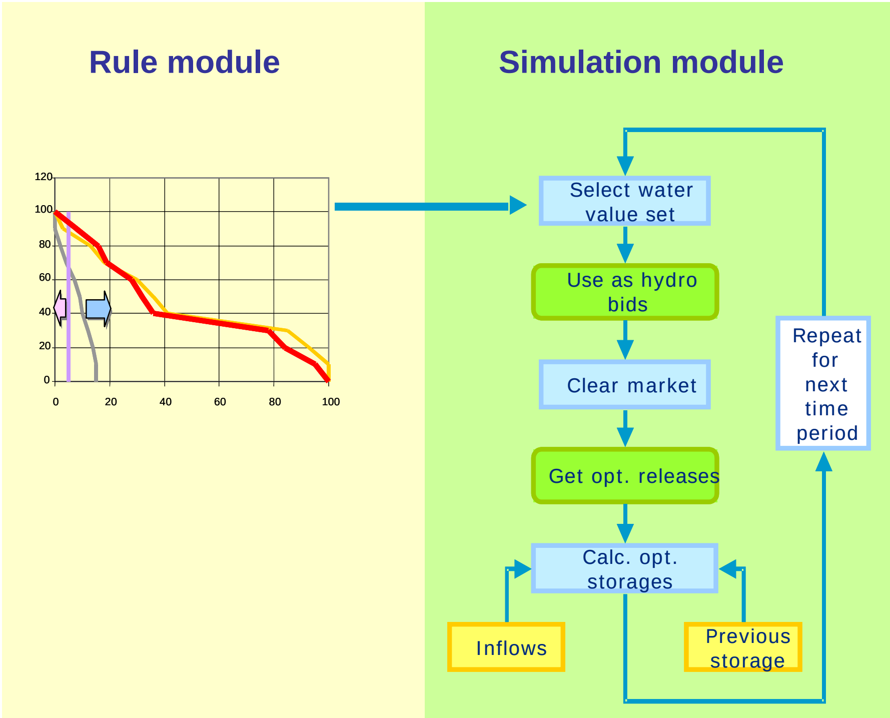
Source: ECON

The simulation is regional and normally includes elastic demand[10], hydro plant (bidding in at their water value) and a non-hydro generation plant set. In a given period, given the thermal plant costs, the marginal water values[11], the market structure (such as cross border capacities and any intra-temporal constraints) and electricity market demand curve, the model matches supply and demand to maximise total social surplus. From the solution, prices, generation levels, demand levels, trade levels and so forth can be obtained for that period. Figure 6 shows how the rule module and the simulation module are combined.

[10] For this paper we have used actual consumption levels as the demand.

[11] The marginal water values can be thought of as a marginal fuel cost; hence the model does not make (and does not need to make) any distinction between hydro and thermal plant in matching supply and demand.

Figure 6. The rule module (the calculation of the DCR and DCS) and the simulation module (the market clearing).



Source: ECON

The multi-period simulation process is as follows. First, a series of inflows to each reservoir in the model is generated (using for example statistical methods based on historical inflow distributions, or an actual historical inflow series) for a desired time horizon of the study. Starting at the first period of the time horizon and a beginning storage level (and hence water value from the DCS) for each reservoir, the market clearing model is solved and market prices, generation levels, and so on are obtained for the period. The storage levels in the reservoir are adjusted by the inflows for the period less water released, and the process is repeated sequentially for each period of the analysis. In this way the behaviour of the market, including the operation (and hence storage trajectories) of the hydro reservoirs can be simulated, and the effectiveness of the storage conservation measures assessed within the simulated market environment. A key element of these simulations is that the hydro operators in the simulations do not know what the future inflows will be, but rather base their decisions on their current storage levels, market structure, and potential future hydrological conditions. This avoids the problem of assuming perfect model foresight.[12]

3.2 Model input

The possible amount of input to the model is vast. Ideally one would wish to use hourly figures for among others temperatures, power demand, available production capacity and capacity on interconnectors. We have selected the variables that are most important for the analysis as described below.

It is not enough to put in time series with actual fuel prices, inflow etc. To calculate water values one must also use expected development at any point. For example if the coal price collapses in week 33, it will not change the water value in week 32. Instead, expected coal prices must be used.

It is time consuming for the model to change the expectations. For that reason, we have limited the frequency of updates of expectations to every four week.

For the analysis of market power, we have changed the expectations for variables listed below:

- Fuel prices
- CO_2-prices
- Availability of nuclear capacity
- Availability of interconnectors
- Precipitation
- Power consumption

Temperatures will not be included. Instead, we use demand as observed hour by hour. The demand does respond on price signals, but those are small, and we have chosen not to include price elasticity.

[12] For this paper we have essentially assumed perfect foresight for the coming four weeks, but uncertainty following that period.

4 Results

The focus in this paper is on the period from 2001 to 2006. This period was chosen since it covers a later period than what has been included in previous studies and since it is a period with large fluctuations in the market. We will however not model the entire period, but will instead focus on periods of particular interest.

The level of water in the reservoirs at a certain point of time can be a result of market power. However, if we study long consecutive periods without calibrating the reservoir levels, small errors in the calculation. In order to make it possible to interpret the result it is necessary to divide the simulations into shorter time-periods, i.e., we can not study the full period of water values and production values may lead to large accumulated differences 2001-2006 in one simulation. The drawback is that restarting the simulations and re-calibrating the reservoir levels may hide effects of market power.

It would be ideal to start the model simulations at a point were we believe that the reservoirs are as expected in a perfect competition situation. Such periods could be at the end of October when the hydro level is highest. This was, however not the case in e.g. 2006.

4.1 Choice of periods

We have chosen to study three time periods. The possibilities to exploit market power are likely to be higher in shortage periods, when the system is operating close to the capacity limits. In the Nordic system the relevant capacity constraint is often the energy constraint, although the effect capacity is occasionally also binding. We would thus like to study the risk of market power in such high risk periods, but also more normal periods are of interest.[13] We have thus chosen two periods that intent to reflect both of this: summer-winter 2002/03 and the summer

[13] It is not necessarily always the case that the potential for market power is highest in shortage periods. According to Damsgaard and Munthe (2007) the potential for market power might actually be higher in a wet year.

to autumn 2006. The autumn of 2002 was an extreme dry period[14] and the summer and autumn of 2006 was characterized by low reservoir levels. As a contrast to these two shortage periods, we have also chosen to study a period that is as close to normal as possible. 2001 can be characterized as a relatively normal year in terms of temperatures and precipitation. We have thus chosen one "normal" period and two dry periods. An important difference between 2002 and 2006 is that from 2005 the European system for emissions trading was introduced, which increased the marginal cost of fossil-fuelled power plants.

4.2 Shortage situation: 2002/03 and 2006

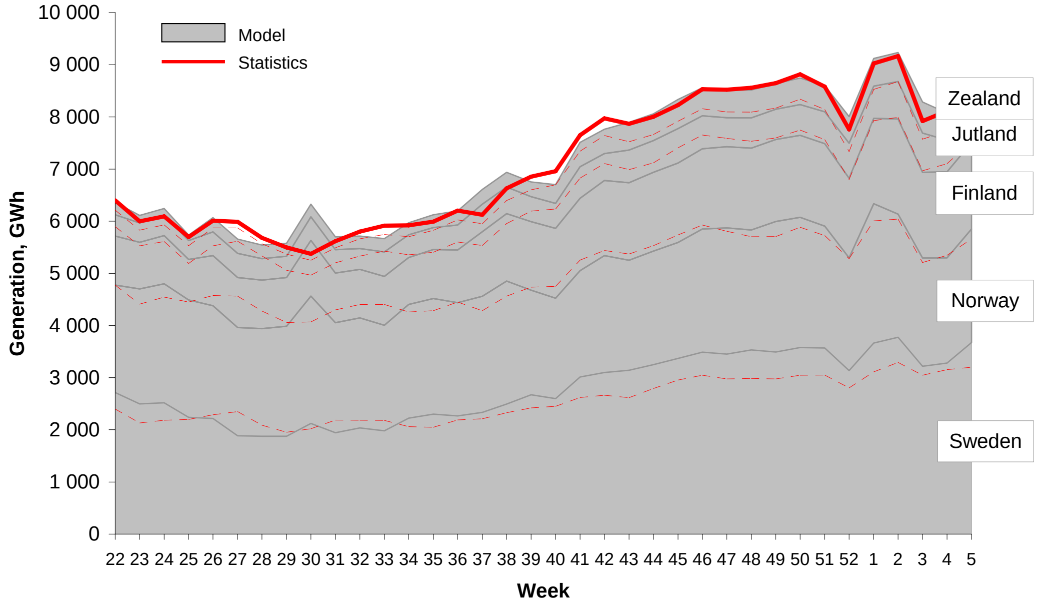
4.2.1 Summer to winter 2002/03

The autumn 2002 was extremely dry and should thus strengthen the possibilities for market power. We have thus chosen to study the period from the beginning of the summer 2002 (week 22) until week 5 in 2003. Figure 7 shows the weekly power production in the Nordic area during the studied period and compares it with the modeled production. 2002. The solid line shows the actual generation in the different market areas, while the area graph shows the modeled generation in each area.

In total, it seems like the generators produced approximately at the same level as the model suggest they should. The figure does not clearly show the divisions between countries. From the autumn (week 40) the actual production in Norway was higher than the model suggests which was compensated by lower production in Sweden during the same time. The Finnish production was generally somewhat higher in reality compared with the model, while the opposite was the case for both east and west Denmark.

[14] ECON has previously estimated that the probability of a precipitation level as low or lower than what was observed in the autumn 2002 is less than 0.5%.

Figure 7. Weekly power production in the Nordic area summer to winter 2002/03



Source: Model simulations, Nord Pool and national TSOs

There are several interpretations to the perceived "overproduction" in Norway during the autumn. One is that it was an attempt to exploit market power through an increased shortage in the winter. There are however also alternative explanations, where the "too high" generation in Norway is explained either by release from multi-year storage (which is not perfectly captured in the model) or by late realizations of the actual situation. We thus continue with studying prices and revenues of the producers to assess what interpretation seems most plausible.

Figure 8 illustrates the deviation between the actual prices and the modeled prices during the period week 22 (start of summer) 2002 to week 5 2003. For all areas except Jutland, the actual prices over the period were below the simulated prices. The actual prices were above the simulated prices only for a short period in December 2002 and January 2003. We have not simulated the continued winter up to the spring 2003, but the actual prices return to, or below, the prices suggested by the model simulation. There is no reason to believe that extending the simulations for a longer time period would result in substantially different conclusions.

Figure 8. Mark-up, actual prices vs. modeled prices, summer to winter 2002/03

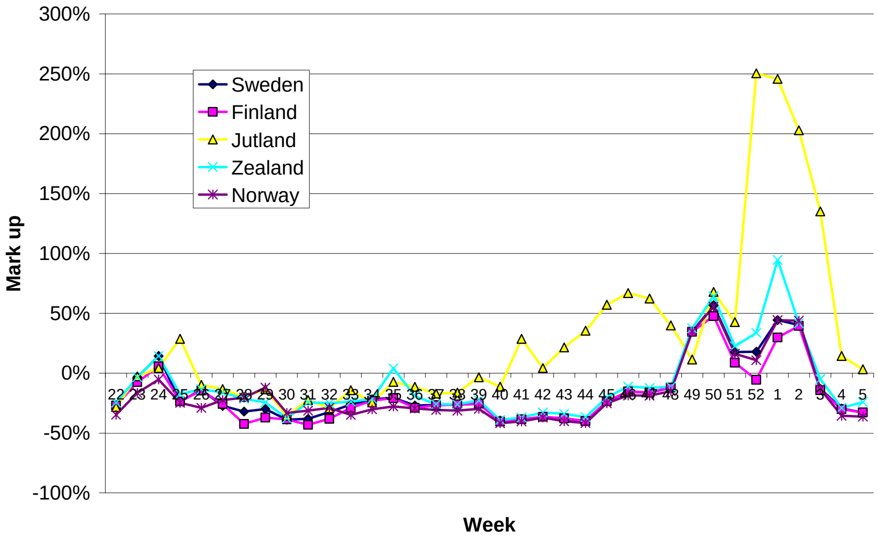


Table 1. Average modeled and actual prices, summer to winter 2002/03

Area	**Average modeled price, €/MWh**	**Average actual price, €/MWh**	**Mark-up, %**
Sweden	42.7	37.8	-12%
Norway	42.4	36.7	-13%
Finland	43.7	37.2	-15%
Jutland	26.2	31.0	18%
Zealand	40.7	38.2	-6%

Source: Own calculation, model simulations and Nord Pool

On average, the actual prices were between 6 and 15 per cent below the modeled prices in the different Nordic areas as shown in Table 1 except for Jutland were the average actual prices were 18 per cent above the simulated prices. In general the low prices in the beginning of the studied period (over the summer and autumn) could be interpreted as a market power strategy shifting hydro production from high demand period (winter) to low demand period (summer/autumn). The question is if this is a reasonable interpretation.

Table 2 shows the revenues of the generators and the expenditure of the consumers given actual prices and production/consumption and the simulated prices and production/consumption respectively. In all areas except Jutland the expenditure of the consumers are less given actual prices and volumes, compared with the expenditures suggested by the model. Looking at the producers, the revenues for generators in Sweden and Denmark East are also clearly less in reality compared with the model, while the Norwegian and Finnish generators approximately have the same revenues with the actual prices and production and what is suggested by the model. Only in Denmark West are the revenues and expenditures higher in reality than in the model. The revenues of the generators is about 11 per cent higher using real data compared to the model results, and the expenditures of the consumers about 20 per cent higher.

Table 2. Revenues and expenditure per country, million €. Week 22 2002 to week 5 2003[15]

Revenues generators	**Actual prices and production**	**Simulated prices and production**	**Difference**
Nordic area	***10,271***	***11,294***	***-9%***
Sweden	3,761	4,602	-18%
Norway	3,372	3,402	-1%
Finland	2,118	2,167	-2%
Jutland	544	490	+11%
Zealand	475	619	-23%
Expenditure consumers	**Actual prices and consumption**	**Simulated prices and consumption**	
Nordic area	***10,730***	***11,877***	***-10%***
Sweden	4,229	4,653	-9%
Norway	3,295	3,701	-11%
Finland	2,343	2,716	-14%
Jutland	463	387	+20%
Zealand	400	420	-5%

Source: Own calculations, model simulations, Nord Pool and national TSOs.

Our model simulations thus indicate a too low production in Denmark and a shift in production primarily in Norway from high to lower load periods. The latter is however difficult to interpret. Given that it does not seem to have resulted in higher average prices over the period, higher revenues for the Norwegian producers or higher expenditure for the Norwegian consumers, we can not conclude that the Norwegian pattern is a result of market power. The Danish situation is different. The actual production in eastern Denmark (Zealand) was lower than the production suggested by the model, but this has not resulted in higher revenues for the producers nor higher expenditures for the consumers. In western Denmark (Jutland) actual prices have been higher than the modeled prices and we conclude that this is an indication of exploitation of market power in western Denmark during this period.

4.2.2 Summer and autumn 2006

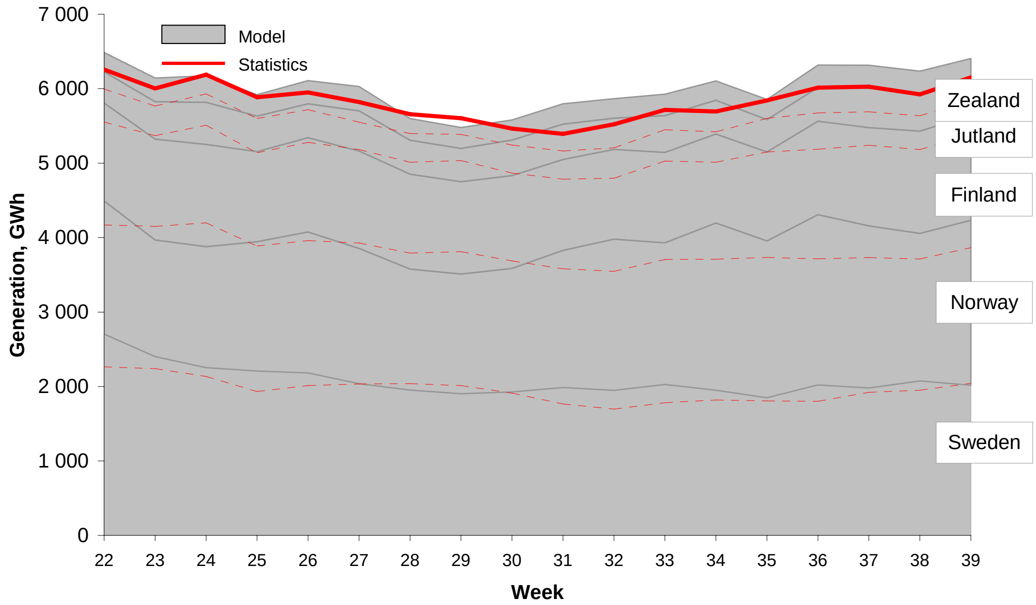
During the summer and autumn of 2006, a number of price influencing events happened. The main drivers for price movements in the period was low snow melting and low precipitation in the beginning of the period, massive shutdown of nuclear power in Sweden from week 33, and heavy rain in week 36.

Figure 9 shows the production figures in the Nordic area. Actual production in the Nordic region was below the model predictions almost in every week throughout this period. Actual production in Sweden and both Danish areas was below the modeled production for almost all weeks. In Norway the actual production was above the modeled production in the first half of the period and lower in the second half. In total, the actual Norwegian production was somewhat below the modeled production. The Finnish production was in total above the modeled production.

The production figures are also reflected in the trade. According to the model, Norway should have imported more than 2 TWh from week 22 to week 31. In reality, Norway exported almost 1 TWh during these weeks.

[15] Note that this calculation assumes that changes in the spot prices are directly pass-through to both the consumers and the producers. In reality this is not the case. The revenues and expenditures using the actual prices and production/consumption levels may thus deviate from actual revenues/expenditures.

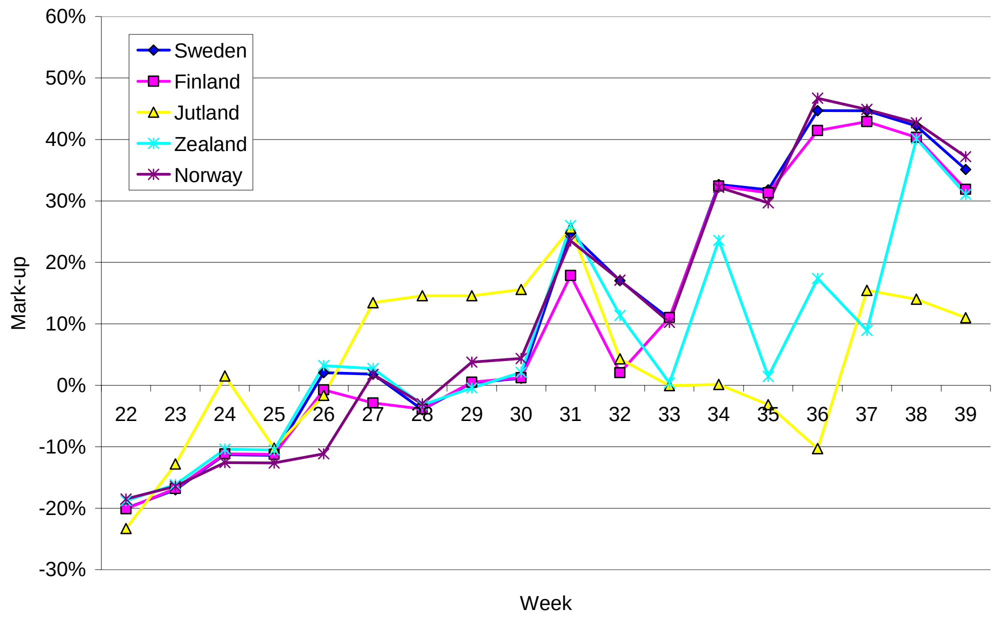
Figure 9 Weekly power production in the Nordic area summer and autumn 2006



Source: Own calculations, model simulations and Syspower

Figure 10 shows the mark-up between observed weekly prices (spot prices) and the modeled during the period week 22 to week 39 2006. In the beginning of the period, the modeled prices are higher than the observed market prices, i.e., a negative mark-up. Furthermore, the modeled prices are for all price areas relatively flat during the first weeks, which is not revealed by this figure. One reason for the flat price curve in the model is that we have assumed that the market knew that there was little snow in the mountains. The problem is that the estimates for snow reservoirs can vary significantly between different analysts and rumours say that a large producer (Statkraft) overestimated the snow magazines with as much as 10 TWh.

Figure 10 Mark-up, actual prices vs. modeled prices, summer to autumn 2006



From week 26 (end of June) actual spot prices and the modeled prices converge to almost exactly the same level, but starting in week 31 the observed spot prices start to increase substantially compared to the modeled prices in all areas except Jutland. For the entire period, the actual prices are 6-12 per cent higher than the modeled prices in the different areas as shown in Table 3.

Table 3. Average modeled and actual prices, summer and autumn 2006

Area	**Average modeled price, €/MWh**	**Average actual price, €/MWh**	**Mark-up, %**
Sweden	50.3	56.4	12%
Norway	50.2	56.1	12%
Finland	51.0	56.1	10%
Jutland	46.6	49.3	6%
Zealand	49.9	52.7	6%

Source: Own calculations, model simulations and Syspower

The model results are consistent with a market power scenario, in which the producers overproduced in the summer in order to create a shortage situation in the autumn. The effect was also a higher actual price than the modeled prices. However, it is difficult to draw any firm conclusions. As mentioned above, the prognosis regarding snow reservoirs are uncertain and errors in the estimations of these may very well explain the observed difference. However, in contrast with the studied period 2002/03 the average actual prices over the period were higher than the modeled prices. As shown in 4 both the total revenues of the generators and the total expenditure for the consumers in the Nordic region was 7 per cent higher given actual prices compared with the modeled prices (remember that the actual consumption is used in the simulations), with higher expenditure in all market areas.

Table 4. Revenues and expenditure per country, million €. Week 22-39, 2006

Revenues generators	**Actual prices and production**	**Simulated prices and production**	**Difference**
Nordic area	***5,813***	***5,423***	***7%***
Sweden	1,960	1,882	4%
Norway	1,889	1,712	10%
Finland	1,346	1,169	15%
Jutland	256	263	-3%
Zealand	362	397	-9%
Expenditure consumers	**Actual prices and consumption**	**Simulated prices and consumption**	
Nordic area	***6,164***	***5,749***	***7%***
Sweden	2,268	2,044	11%
Norway	1,824	1,735	5%
Finland	1,508	1,451	4%
Jutland	328	304	8%
Zealand	235	216	9%

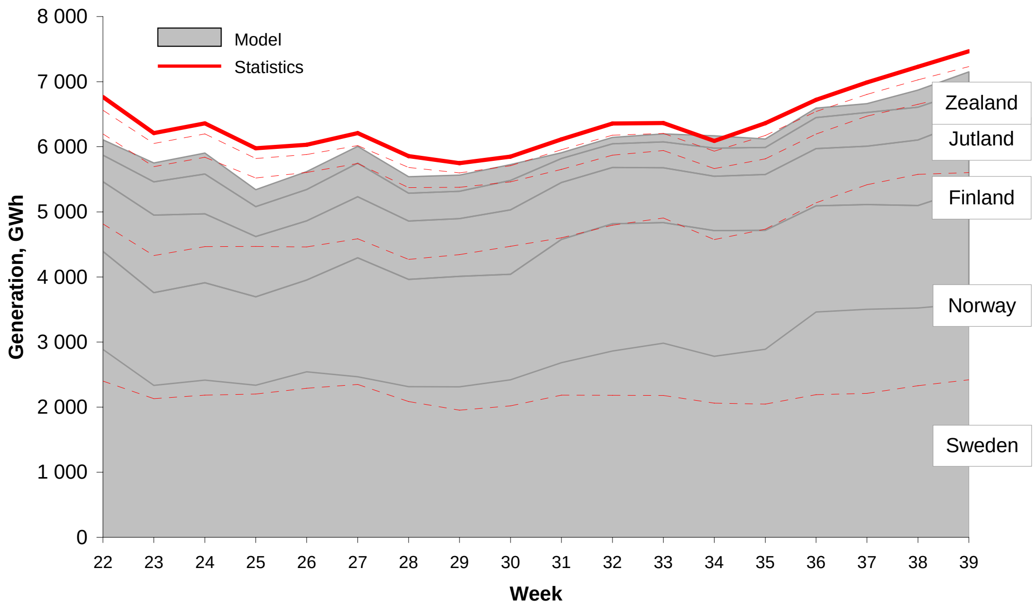
Source: Own calculations, model simulations and Syspower

4.3 “Normal” situation: Summer and autumn 2001

As already stated above 2001 can be seen as a representative normal year in terms of precipitation and temperature. The reservoir levels in Sweden were higher than normal while the opposite was the case in Norway, but on average the reservoir levels were about normal. The summer and autumn 2001 could thus represent a “normal” situation.

The actual production in the Nordic region was higher than the model predicts as shown in Figure 11. The actual production in Sweden was well below the modeled production throughout the period and the difference between actual and modeled production increased over time. At the same time, the actual production in Norway was clearly above the modeled production and the combined production in Norway was at least as large as the model suggests. Furthermore, while the Finnish actual production exceeded the production in the model the opposite was the case for Denmark. In total, the actual production was higher in every week compared with the model results.

Figure 11 Weekly power production in the Nordic area summer and autumn 2001



Source: Own calculations, model simulations, Syspower and national TSOs

As shown in Figure 12 the modeled prices and actual spot prices follow each other closely during the summer and autumn 2001 for most of the time. In the initial five weeks the modeled prices are higher than the actual prices in all areas but Jutland where the actual and modeled prices are close almost from the start. For the remaining of the period, the spot prices are at the same level, or slightly higher than the modeled prices, except in Finland where the modeled prices are clearly above the actual prices in the latter half of the studied period. For the entire period, the time average actual prices were about 2 and 16 per cent below the modeled prices as shown in Table 5.

Figure 12 *Modeled power prices and spot prices in the Nordic region summer and autumn 2001*

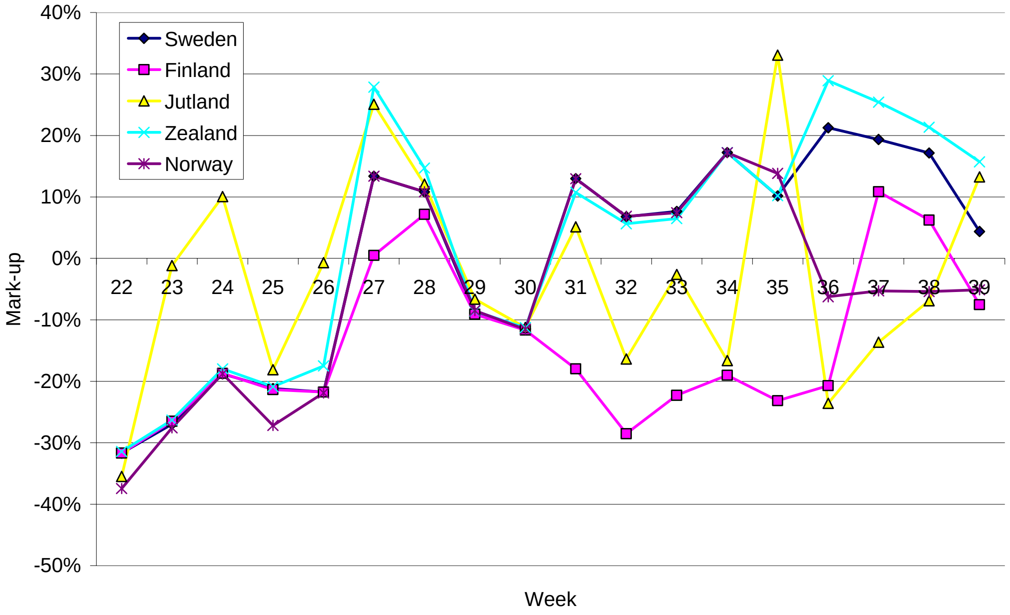


Table 5. *Average modeled and actual prices, summer and autumn 2001*

Area	Average modeled price, €/MWh	Average actual price, €/MWh	Mark-up, %
Sweden	23.2	22.2	-5%
Norway	25.0	22.7	-9%
Finland	26.5	22.2	-16%
Jutland	25.4	24.1	-5%
Zealand	23.2	22.8	-2%

Given the “negative” mark-up in all market areas the total expenditure of the Nordic electricity consumers will also be lower using actual prices (remember that the consumption levels have been fixed to the observed consumption in the simulations). As shown in Table 6 the total expenditure for the consumers is about 9 per cent lower given the observed prices than it would have been with the prices generated by the model.

Table 6. Revenues and expenditure per country, million €. Week 22-39, 2001

Revenues generators	**Actual prices and production**	**Simulated prices and production**	**Difference**
Nordic area	***2,580***	***2,627***	***-2%***
Sweden	875	1,139	-23%
Norway	1,042	732	42%
Finland	456	453	1%
Jutland	137	209	-35%
Zealand	71	94	-24%
Expenditure consumers	**Actual prices and consumption**	**Simulated prices and consumption**	
Nordic area	***2,445***	***2,681***	***-9%***
Sweden	908	935	-3%
Norway	755	836	-10%
Finland	521	635	-18%
Jutland	162	172	-6%
Zealand	100	103	-3%

Source: Own calculations, model simulations, Syspower and national TSOs

5 Conclusion

Using a sophisticated model for the Nordic power market, we have studied three periods with different characteristics with the aim to detect abuse of market power. The summer and autumn 2001 represent a normal situation, while the summer and autumn of 2002 and 2006 represent two dry periods. In 2006 the European Union Emissions Trading Scheme had been introduced which increased the marginal cost of fossil fuelled power production.

The major problem with detecting market power in a hydro dominated system is that there is no clear measure of the relevant marginal cost in hydro power plants. The hydro production is determined by the expectations about future power prices. Differences in expectations may thus create different production patterns, without that necessarily being a sign of market power.

Furthermore, the hydro reservoirs in Norway and Sweden are not at all homogenous. Some reservoirs are very large and can store water for up to three years. Other reservoirs can only store water in weeks or days. In the model we do not split reservoirs in different classes, both due to additional complexity it would cause and lack of data. If the big reservoirs have more or less water that “normal” that can make producers more or less willing to produce power compared with the model results.

Our results indicate that the market prices in the autumn 2006 might have been affected by market power. The observed prices are 6-12 per cent higher than the modeled prices in the different market areas, but there might be other explanations to this price difference. The actual prices were then initially lower than the model suggests, but this turned around after some weeks and on average the prices became higher than the modeled prices. The explanation for the price difference is that the Norwegian production levels initially were higher in reality than in the model. Shifting hydro production in order to decrease production in high demand periods resulting in a higher average price level is consistent with market power behaviour. However, in the model we update data on inflows, fuel price expectations etc. on every four week. We have then used the actual inflow data over the coming four weeks, which means that essentially the producers have perfect foresight regarding hydro inflow over that period. In reality, the producers can make fairly accurate predictions over approximately a two week period, but it then becomes more difficult. Furthermore, and probably more important, we assumed that the producers had accurate knowledge of the snow reservoirs. During the summer 2006, the actual (tight) hydrological situation was gradually realised and this is probably (also) an important explanation to the observed price pattern.

In the period summer to winter 2002/03 prices also became very high driven primarily by an extremely dry autumn. Our results indicate that it is only in Jutland where market power might have contributed to pushing prices upwards. Actual prices in Jutland were about 18 per cent higher than the simulated prices, although the Jutland prices were still below the prices in the other market areas on average. In all other market areas, the actual prices were below the simulated prices. For the “normal year” 2001 actual prices were below the simulated prices in all market areas.

In both 2002 and 2006 it was primarily the Norwegian hydro producers who "overproduce" in the early phases relative to our model results. This can however be caused by differences in expectations just as well as strategic behaviour.

When studying individual hours there are hours with large deviation between the modeled prices and the actual prices. These deviations are however in both directions and seems to be more a reflection of stochasticity in the electricity price formation that are not captured by the modeled than market power. Abuse of market power in individual hours can however not be ruled out, but the economic effects then seems to be limited.

The overall conclusion is that the most of the price variations observed over the last years can be explained by market fundamentals assuming perfect competition. The main exception is Jutland in 2002/03 where prices were clearly above what the model suggests. The results for 2006 are also consistent with market power in a hydro dominated power market. However, it is not possible to rule out that the deviations between the actual and simulated prices are caused by differences in expectations between the producers and our model assumptions. The price deviations are not large enough to rule that out.

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